Docket No. 2019-184-E

Independent Third Party Consultant Final Report Pursuant to South Carolina Act 62

Prepared for:

Public Service Commission of South Carolina

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Submitted by:

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Executive Summary

On May 16, 2019, the Governor of South Carolina signed into law the South Carolina Energy Freedom Act (Act 62), which addresses the state's implementation of parts of the Public Utility Regulatory Policies Act (PURPA). There were many elements to PURPA. Section 210 pertained to a new class of generators identified as qualifying facilities (QFs) and an obligation on investor-owned electric utilities to purchase power from QFs at the utilities' avoided costs, which are the incremental cost to the utility of generating or purchasing this power. These elements of PURPA, along with obligations by South Carolina electric utilities to provide a standard offer under which they would purchase power from small power producer QFs, are a major focus of Act 62.

Act 62 directs the Public Service Commission of South Carolina (Commission) to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section."[1]

Under the standard offer provisions of Act 62, electric utilities are required to implement a Standard Offer Purchased Power Tariff, a Power Purchase Agreement (PPA), and Terms and Conditions that are available to small power producers that are 2 MW or smaller. The main areas of review and analysis are solar integration charges; avoided costs; and appropriate PPA terms and conditions. Each is reviewed below.

Solar Integration Charges

Solar integration costs are central to two aspects of DESC's filing: (1) as their proposed Variable Integration Charge (VIC) for solar generation, and (2) embedded in their proposed avoided cost rates for solar generation. The proposed VIC is an estimate of the cost of maintaining additional reserves due to increased solar capacity. The resulting VIC estimate is $4.14/MWh; this is the amount that DESC is proposing to charge to approximately 700 MW of solar projects with signed Power Purchase Agreements containing a clause requiring them to pay variable integration charges.

DESC's calculation of its avoided costs of solar generation included the assumption that it will need to maintain higher levels of reserves than it would without solar generation reserves. The effect of this assumption is to decrease its projected avoided costs for solar generation by approximately $7/MWh, or almost 30%, in 2020-2024, and $10/MWh, or 40%, in 2025-2029.

Areas of investigation with respect to DESC's solar integration charges included the following:

- Analysis of Solar Intermittency
- Risk Threshold

[1] Act 62. Section 58-41-20. (A)

- Constant Reserve Levels
- Alternative Mitigation Options

In Power Advisory's opinion, DESC's proposed values for the VIC, and solar integration costs embedded in its proposed avoided costs, are not adequately supported by the evidence and recommend that lower solar integration costs be employed. In addition, as provided for in Act 62, we recommend that the Commission initiate a study with an independent consultant to assess DESC's solar integration costs.

Avoided Costs

DESC discussed the risk of overpayment and said that the 10-year term mitigates against that risk relative to longer PPA lengths. Other parties asserted that locking in current low avoided costs with long term contracts would be in ratepayer's best interest because natural gas prices are low and forecast to increase significantly.

Parties identified factors that would result in avoided costs increasing or decreasing in the future, benefiting or harming ratepayers given the long-term contracts with QFs at a fixed price based on current avoided costs. A critical determinant of future avoided costs was identified as natural gas prices, with intervenors noting that the Energy Information Administration forecasts gas prices to triple in 30 years. Another possible driver of higher avoided costs cited was a potential carbon tax.

Avoided Energy Costs

DESC projected avoided energy costs for both solar and non-solar QFs using a simulation model of their system. Our review of DESC's avoided energy costs focused on the following areas:

- Transparency, where we felt that DESC's filing was deficient
- Technology Neutral Approach, where we believe that DESC's approach is potentially discriminatory against certain project configurations
- Selection of Pricing Periods, where we recommend that in future avoid cost filings DESC provide support for its pricing periods

Avoided Capacity Costs

Our review of DESC's avoided capacity cost estimates focussed on the following areas:

- Capacity Value Methodology, where we recommend that capacity value should be estimated using the ELCC methodology

- DESC Capacity Cost Methodology, where we recommend that capacity value should be determined based on the avoided cost of a combustion turbine not consider the projected cost of market purchases

- DESC Capacity Cost Assumptions, where we recommend that the change in capacity between the base case and the change case be aligned with the size of the combustion turbine that DESC adds for additional capacity (93 MW) rather than 100 MW differential between the base and change case, and a 20-year asset life be assumed

PPA and NOC Terms and Conditions

Power Advisory discussed the concept of commercial reasonableness as it relates to the Power Purchase Agreements and Notice of Commitment to Sell Forms. We also discussed the implications of a 10-year contract term identified in Act 62.

In the course of this proceeding, the two sides (namely DESC and SBA) came to agreement on many matters which Power Advisory found to be fair and reasonable. The matters that were unresolved were as follows:

DESC's PPA Terms and Conditions

- Liquidated Damages and Extension Payments
- Guaranteed Energy Production
- Energy Storage
- Termination Payment

Notice of Commitment to Sell Form

- Limiting PPA eligibility following
- 365-day in-service deadline
- Eligibility pre-conditions

For each of these issues, Power Advisory provided a summary of the positions of both sides and provided its independent opinion based on the evidence provided.

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1. INTRODUCTION

On May 16, 2019, the Governor of South Carolina signed into law the South Carolina Energy Freedom Act (Act 62), which addresses the state's implementation of parts of the Public Utility Regulatory Policies Act (PURPA). PURPA was originally enacted by the US Congress in 1978.[2] There were many elements to PURPA. Section 210 pertained to a new class of generators identified as qualifying facilities (QFs) and an obligation on investor-owned electric utilities to purchase power from QFs at the utilities' avoided costs, which are the incremental cost to the utility of generating or purchasing this power (see discussion in Chapter 3). These elements of PURPA, along with obligations by South Carolina electric utilities to provide a standard offer under which they would purchase power from small power producer QFs, are a major focus of Act 62. QFs include small power producers that utilize renewable energy to generate electricity and range are 80 MW or smaller as well as cogeneration facilities.

Act 62 directs the Public Service Commission of South Carolina (Commission) to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section."[3]

Under the standard offer provisions of Act 62, electric utilities are required to implement a Standard Offer Purchased Power Tariff, a Power Purchase Agreement (PPA), and Terms and Conditions that are available to small power producers that are 2 MW or smaller. Standard offers are employed to recognize that small projects are less able than large projects to bear the costs associated with negotiating a PPA and ascertaining the terms and conditions under which the local electric utility would be willing to purchase power.

Act 62 applies to all utilities that are regulated by the Commission, except that electric utilities serving less than 100,000 customers are exempt from the renewable energy programs outlined in Chapter 41 of the Act. As such, the Act applies to Dominion Energy South Carolina, Inc. (DESC); and Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP), collectively the "Companies". Pursuant to Act 62 the Commission opened three dockets for the three utilities to

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[2] On September 19, 2019, FERC issued a Notice of Proposed Rulemaking on Qualifying Facility Rates and Requirements and Implementation Issues Under PURPA (NOPR), which proposes to scale back some of the requirements of PURPA. FERC characterizes the intent of the NOPR to "rebalance the benefits and obligations of the Commission's PURPA Regulations in light of the changes in circumstances since the PURPA Regulations were promulgated in 1980." (para 4.) Power Advisory notes that the Commission's actions in these dockets are in response to Act 62, but that Section 58-41-10 (B) does specify that "implementing this chapter, the commission shall treat small power producers on a fair and equal footing with electrical utility owned resources by ensuring that: …power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA."

This is only a notice of proposed rulemaking, which should not be interpreted as the promulgation of final regulations.

[3] Act 62. Section 58-41-20. (A)

which the Act applies, for DESC Docket No. 2019-184-E, DEC Docket No. 2019-185-E, and DEP Docket No. 2019-186-E.

With respect to implementing the Act, the Commission is directed:

> "to address all renewable energy issues in a fair and balanced manner, considering the costs and benefits to all customers of all programs and tariffs that relate to renewable energy and energy storage, both as part of the utility's power system and as direct investments by customers for their own energy needs and renewable goals. The commission also is directed to ensure that the revenue recovery, cost allocation, and rate design of utilities that it regulates are just and reasonable and properly reflect changes in the industry as a whole, the benefits of customer renewable energy, energy efficiency, and demand response, as well as any utility or state specific impacts unique to South Carolina which are brought about by the consequences of this act."[4]

The Act requires Commission decisions to reflect a careful balancing of interests:

> "Any decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public."[5]

Further guidance regarding how the interests of QFs will be protected and balanced with customers' interests flows from the direction to:

> "treat small power producers on a fair and equal footing with electrical utility owned resources by ensuring that:
>
> (1) rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs;
>
> (2) power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA; and
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> (3) each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited

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[4] Act 62. Section 58-41-05.

[5] Act 62. Section 58-41-20. (A)

> to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment."[6]

Act 62 also authorizes the commission "to employ, through contract or otherwise, third party consultants and experts in carrying out its duties under this section, including, but not limited to, evaluating avoided cost rates, methodologies, terms, calculations, and conditions under this section."[7] Power Advisory LLC (Power Advisory) was engaged by the Commission on September 3rd to serve as the independent third-party consultant in the three dockets filed pursuant to Act 62. This is Power Advisory's report to the Commission outlining our findings from the review of the materials filed by the parties and the hearings before the Commission regarding DESC in Docket No. 2019-184-E.

1.1 Relevant Experience of Power Advisory

Power Advisory is a management consulting firm focused on the North American electricity sector. The lead consultant on this project and Power Advisory President, John Dalton, has over thirty years of experience as a senior electricity market analyst and policy consultant. John has testified in over 25 proceedings before state and provincial regulatory commissions; advised jurisdictions on the design of renewable energy procurement frameworks including standard offer programs; and has extensive experience overseeing and reviewing quantitative analyses including avoided cost estimates, electricity price forecasts, generation technology cost estimates and production cost modeling.

Recent Power Advisory consulting assignments related to the mandate of South Carolina Act 62 include drafting and review of Power Purchase Agreements for renewable energy resources including variable output resources such as solar; assessing renewable technology costs; evaluating the requirements to integrate variable output renewable energy resources and reviewing utility avoided costs. Power Advisory has overseen the development, reviewed the implementation, and advised on changes to renewable energy procurement programs in Alberta, British Columbia, Massachusetts, New York, Nova Scotia, Ontario, Rhode Island and Vermont. For some of these projects, Power Advisory was responsible for drafting the Power Purchase Agreement. While serving as the Nova Scotia Renewable Energy Administrator, Power Advisory drafted the PPA which was accepted by the Utility and Review Board. Relevant to the consideration of variable energy integration charges, Power Advisory prepared a report for the Government of Canada on the integration of variable output renewable energy sources focusing on the importance of essential reliability services. Power Advisory team members have a long history of running and overseeing the specification of production cost models (and reviewing the results of these models) such as DESC used to develop their avoided cost estimates.

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[6] Act 62. Section 58-41-20. (B)

[7] Act 62. Section 58-41-20. (H)

1.2 Power Advisory Review and Participation in Proceeding

As indicated, Power Advisory was engaged by the Commission on September 3, 2019. Hearings in this proceeding began on October 14th after the parties submitted Direct, Rebuttal and Surrebuttal Testimony. Power Advisory issued interrogatories and requests for production of documents to DESC, reviewed the interrogatory responses and documents provided by the parties as well as reviewed the Direct, Rebuttal and Surrebuttal Testimony and monitored the hearings. Given the schedule in this proceeding which requires a Commission decision by November 16th, we were requested by the Commission to issue a final report on or before November 4th to provide the parties an opportunity to comment on the report.

Act 62 specifies that "the qualified independent third party's duty will be to the commission. Any conclusions based on the evidence in the record and included in the report are intended to be used by the commission along with all other evidence submitted during the proceeding, to inform its ultimate decision setting the avoided costs for each electrical utility."[8] We have sought to follow this direction and ensure that our conclusions are based on the evidence in the record. The fact that the schedule for this proceeding was compressed and issues with the transparency of DESC's filing limited our ability to reach conclusions in a number of areas. Where necessary and appropriate, we rely on our expertise in the electricity sector to evaluate and analyze the findings and information presented by the parties.

1.3 Contents of the Report

Our report consists of four chapters, the first of which is this Introduction. Chapter 2 reviews DESC's estimates of solar integration costs, including the Variable Integration Charge estimated by DESC and the solar integration costs embedded in the avoided costs projected for solar QFs.[9] Although DESC used different methodologies for the VIC and for its avoided costs, the issues brought up in these proceedings are sufficiently related that we are addressing them together. This chapter discusses DESC's estimates of solar integration charges, the methodologies that were used to develop these estimates, various parties' criticisms of these methodologies, and the resulting charges.

The next chapter, Chapter 3, addresses other aspects of the rates based on avoided costs (i.e., all rates except the VIC). It is organized along the primary areas of focus of Act 62, and includes our review of the definition of avoided costs, a discussion of potential risks from avoided cost-based rates, a review of the avoided cost methodology proposed and the resulting avoided cost

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[8] Act 62. Section 58-41-20. (I)

[9] We elect to review the solar integration costs before reviewing total avoided costs because an important element of DESC's avoided cost analysis are its assumptions regarding the modeling of these integration costs. Therefore, understanding our assessment of the solar integration cost modeling assists in understanding our assessment of DESC's avoided cost analysis.

estimates, and responses to major issues regarding these avoided cost estimates identified by parties to this proceeding. Finally, Chapter 4 reviews various terms and conditions that are disputed by the parties pertaining to the proposed PPAs and NOC forms.

Act 62 provides that "The independent third party shall also include in the report a statement assessing the level of cooperation received from the utility during the development of the report and whether there were any material information requests that were not adequately fulfilled by the electrical utility."[10] Power Advisory notes that DESC cooperated as would be expected. However, there are fundamental issues with respect to the transparency of their avoided cost filing and analysis, which causes Power Advisory to temper our assessment of the level of cooperation provided. At times this cooperation was as explicitly required, but not in spirit. Our assessment of the transparency of their avoided cost filing is provided in Chapter 3.

[10] Act 62. Section 58-41-20. (H)

2. SOLAR INTEGRATION CHARGES

2.1 Importance of Solar Integration Charges

Solar integration costs are central to two aspects of DESC's filing: as their proposed Variable Integration Charge (VIC) for solar generation, and embedded in their proposed avoided cost rates for solar generation. The proposed VIC is simply an estimate of the cost of maintaining additional reserves due to increased solar capacity. The resulting VIC estimate is $4.14/MWh; this is the amount that DESC is proposing to charge to approximately 700 MW of solar projects with signed Power Purchase Agreements containing a clause requiring them to pay variable integration charges.[11]

DESC's calculation of its avoided costs of solar generation included the assumption that it will need to maintain higher levels of reserves than it would without solar generation reserves. The effect of this assumption is to decrease its projected avoided costs for solar generation by approximately $7/MWh, or almost 30%, in 2020-2024, and $10/MWh, or 40%, in 2025-2029, as shown in Figure 1.

Figure 1. DESC's Proposed Avoided Costs with and without Additional Reserves [12]

($/MWh)	2020-2024	2025-2029
DESC's Estimate of Avoided Costs	$16.76	$15.66
Avoided Costs Without Additional Reserves	$23.46	$26.08
Difference	$6.70 *29%*	$10.42 *40%*

DESC's estimates of solar integration costs – both the VIC, and as a factor embedded in their avoided cost rates for solar QFs – are based on the cost of maintaining additional reserves in response to the intermittency of solar generation. The reserves used to develop these estimates are specifically reserves that are available within a few minutes. Dr. Tanner defines reserves as follows:

> "Operating Reserves" means the capability of the electric system to quickly increase generation either by turning on quick-start electric generating units or ramping up the generating output of units that are currently online but not operating at full capacity.

[11] DESC Bell Direct, p. 19 line 19 to p. 20 line 14.

[12] DESC Responses to Power Advisory First Interrogatories, #1-7, p.8.

> Available operating reserves are calculated in terms of how much additional generation is available in a given period of time. Operating reserves are needed by an electric system in order to respond to unexpected drops in generation or unexpected increases in load.

DESC maintains three types of such reserves: regulating reserves to respond to fluctuations in frequency and Area Control Error, contingency reserves required under a reserve-sharing agreement with the "VACAR" group of neighboring utilities, and "flexible" reserves "to meet the challenge of solar intermittency and other un-forecasted variations in demand and supply above VACAR contingency reserve requirements".[13] DESC maintains approximately 200 MW of contingency reserves to respond to generator outages, and 40 MW of flexible reserves "for intra-hour load variation" (i.e., before considering solar intermittency).[14] The increase in reserve requirements which is the basis for DESC's estimates of solar integration costs means an increase in flexible reserves.

With respect to the consideration of solar integration costs in its avoided cost methodology, DESC noted that "The most appropriate method of addressing issues created by solar intermittency is to model the system with higher operating reserves. The increase in operating reserves is now part of the model and is reflected in our estimated avoided energy costs."[15] Without these additional reserves, system costs in the change case would be lower, and the resulting estimates of solar avoided costs would be higher.

The VIC estimate was developed by Navigant Consulting, Inc. ("Navigant") rather than DESC itself, but it used a similar approach: "the cost of holding additional reserves is calculated by comparing the PROMOD production costs with and without holding additional reserves required to meet solar uncertainty."[16] Although many of the details are different (modeling software used, hourly profile of the additional reserves modeled, etc.), the general approach is similar, as are most of Power Advisory's concerns.

Both DESC and Navigant modeled the system operating with set amounts of installed capacity, changing slightly over time and different between the base case and change cases, but otherwise fixed. In addition, Navigant briefly analyzed the possibility of adding new capacity, either quick-start gas CTs or energy storage, as possible alternatives to meeting the need for additional reserves, but concluded that "additional resources are not currently feasible for reducing integration costs in any of the solar penetration scenarios".[17]

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[13] DESC Bell Rebuttal, p. 5, lines 5-6.

[14] DESC Bell Rebuttal, p. 4 line 19 to p. 5 line 4.

[15] DESC Neely Direct, p. 10.

[16] DESC Tanner Direct, Exhibit MWT-2, p. 29.

[17] DESC Tanner Direct, Exhibit MWT-2, p. 31. As discussed below, Power Advisory believes that Navigant's analysis of alternative mitigation measures is inadequate.

Participants in this proceeding identified a number of issues with both methodologies. Power Advisory considers the most significant of these issues to be the following:

- Inappropriate choice of data to analyze solar intermittency
- Lack of support for the risk threshold used to determine additional reserve requirements
- Inappropriate modeling of the additional reserve requirements
- Inadequate consideration of alternative sources of reserve capacity.

2.2 Analysis of Solar Intermittency

The additional reserves for solar used by DESC in its estimation of avoided costs (35% of nameplate capacity[18]) and by Navigant in its estimation of the VIC (up to 32% of installed capacity[19]) are based on their analysis of data on solar intermittency. DESC's testimony emphasized that the cost of solar integration is due to its unpredictability: the potential difference between forecast and actual generation. Mr. Bell stated:

> "By comparison, solar generation is a product of uncontrollable factors such as available sunlight and cloud cover, and a solar facility's output is not necessarily responsive to system needs. Because of this variability in generation, DESC must make operational adjustments to follow the energy generated by solar facilities and to maintain sufficient reserve generation capability in order to meet system reliability requirements. In addition to being variable moment to moment, solar generation varies widely from the solar generation forecasts provided by solar operators, which also creates a need for reserves."[20]

DESC's VIC and avoided costs estimates are based on the cost of additional reserves, which are a function of variation between forecast and actual output. The additional reserves should therefore be based on differences between forecast and actual generation – more specifically on differences between the best available forecast, on a timeframe appropriate to setting reserve levels, and actual generation.

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[18] DESC Neely Direct Testimony, p. 10, lines 18-20.

[19] DESC Tanner Direct Testimony, Exhibit MWT-2, p. 17 Table 6 and p. 26 Table 12. Navigant's calculation of the VIC is based on differences between the Initial Solar and the All Solar cases. Table 12 shows a difference of 230 MW in Maximum Additional Reserves Needed in all years (except slightly less in 2020). Table 6 shows a difference of 708 MW in Maximum DESC Solar Capacity in all years. 230 is 32.5% of 708. Navigant adjusts the modelling results to use lower required reserves on some days: either the same amount as in the Initial Solar case, or an intermediate amount.

[20] DESC Bell Direct, p. 12, lines 7-15.

When asked by ORS "Provide the justification of solar capacity additional reserves. Specifically, detail on the analysis done to arrive at the 35% value (page 10/27 of James W. Neely's Direct Testimony)", DESC's reply was:

> "Using 2018 aggregated 15-minute solar generation DESC identified the 15-minute, 1-hour, 2-hour and 4-hour reductions in solar generation ("drops"). In the months of January, February, March, April, October, November, and December, DESC looked at drops before 4pm. In the months of May, June, July, August and September, DESC looked at drops before 6pm. 80 MW is sufficient to cover 96% of the 1-hour drops and is 35% of the maximum capacity analyzed. To cover 100% of the 1-hour drops would require reserves of 101.5 MW or 45% of the capacity analyzed."[21]

When asked "Why did the Company pick the one-hour time frame -- a one-hour time frame to operate the reserves when drops occur in varying lengths?" Mr. Neely replied, "in our opinion, the one-hour reserves is appropriate for balancing the risk versus cost."[22]

However, as Brian Horii of ORS correctly notes in his Surrebuttal Testimony of October 11, "the Company provides no data to support that the drop is the difference between *expected* [emphasis in the original] and actual output. Rather, the Company's response indicates the drop is simply the reduction in solar generation." [23] Many "drops" between one hour and the next (including those before 4 pm in winter/6 pm in summer) are entirely predictable, and to the extent that they are predictable, do not necessitate additional reserves.

Navigant's standard (up to 32% of installed capacity) is somewhat more transparent: "For each solar penetration scenario, the maximum expected drop in solar generation for each year was used to determine the extra operating reserves that need to be held to ensure that the reserve requirements are met."[24] Navigant states that "The forecast uncertainty is developed from the National Renewable Energy Lab's (NREL) Solar Integration Dataset. This is a public dataset that provides both forecasted and real-time solar generation at a large number of sites across the LLS."[25] Navigant calculated "forecast error" by comparing NREL's "actual" generation for 5-minute intervals to NREL's 4-hour-ahead forecast; forecast errors for the 5-minute intervals were then averaged over 15 minute intervals.[26]

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[21] DESC Responses to ORS AIR #2-6, p. 6.

[22] Hearing Vol. 1, p. 400, lines 3-5 and 14-16 (DESC Neely)

[23] ORS Brian Horii Surrebuttal, p. 3, lines 18-21.

[24] DESC Tanner Direct, Exhibit MWT-2, p. 25. As discussed below, there is some confusion about whether Navigant's reserve levels were based on the absolute maximum, or on the largest 1% of drops.

[25] DESC Tanner Direct, Exhibit MWT-2, p. 21.

[26] DESC Tanner Direct, Exhibit MWT-2, p. 21.

Several witnesses questioned the use of a 4-hour-ahead forecast to make decisions about requirements for flexible reserves, which by definition are able to respond within a few minutes. Mr. Horii states:

> "... the 4-hour period is inconsistent with the intended purpose of operating reserves. Operating reserves are carried to address short-term changes in demand or generation. Changes over four (4) hours can be addressed with options that are less costly, such as generation unit rescheduling and the starting of off-line resources."[27]

As Mr. Stenclik notes:

> "the least reserves are required, and the lowest costs will be incurred, if the most accurate, and therefore shortest term forecast, is used…The 4-hour window does not represent state-of-the-art forecasting capability, commercial service offerings, or technical constraints of the DESC fossil generation, but rather the available data in the NREL datasets. In actual operations, the utility can implement a rolling solar forecast that is routinely updated at day-ahead, 4-hour ahead, 2-hour ahead, and real-time intervals. This will allow for rolling decisions that occur throughout the day, rather than at static pre-determined intervals."[28]

When asked by South Carolina Conservation League and Southern Alliance for Clean Energy "Please explain why it is appropriate to base reserve requirements on the 4-hour solar forecast error when the CC plants can start in 2 hours and CT plants start faster", Dr. Tanner responded:

> "The 4-hour forecast is an appropriate estimate for the forecast error because, although some of the CCs can start in 2 hours, there would need to be some lead time between receiving the forecast and discovering that it is less than the expected solar generation. This assumption is that DESC would not be able to know whether the forecast was wrong for at least two hours after receiving the four-hour ahead forecast. This analysis is conservative in that many of the ST plants on the system and a few of the CCs need longer than 2-4 hours to start."[29]

Mr. Stenclik asserts that:

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[27] ORS Horii Surrebuttal, p. 3, lines 13-16.

[28] SACE/CCL Stenclik Direct, Exhibit B, p. 9.

[29] Dr. Tanner's statement was made during a different proceeding before the Public Service Commission (2019-2-E) and is quoted in Mr. Stenclik's Direct Testimony. DESC confirmed, in its Response to South Carolina Conservation League and Southern Alliance for Clean Energy First Data Request 1-13, that its response remains the same in the current proceeding.

> "This response misrepresents the objective of operating reserves. Variable integration reserves are designed to protect against the possibility that the solar forecast is so wrong that there won't be enough reserves to cover any drop in actual solar generation. The operator does not need to determine if the current forecast is accurate; the reserves are being held precisely in case the forecast is wrong. If there is time to determine if the forecast is correct, then there is no need for forecast-error reserves. With a 2-hour ahead forecast there is no need to wait and determine if the solar forecast is accurate. The reserve requirement is based on the forecast amount and already incorporates the risk that the forecast is wrong. If the 2-hour ahead forecast estimates a solar generation level that indicates the need for an additional CC to be operating to supply reserves, the CC can begin to be started immediately." [30]

As noted above, DESC based the estimate of solar integration costs which it used in its own avoided cost calculations on "drops" over a one-hour period, not a four-hour period.

In order to assess the impact of a one-hour-ahead forecast instead of a four-hour-ahead forecast, Power Advisory attempted to replicate the "actual" data used by Navigant based on four NREL sites.[31] This data was used to develop a one-hour ahead forecast for each 15-minute interval based only on extrapolating from earlier data – i.e., without the benefit of a weather forecast, NREL's own 4-hour-ahead forecast, or any information other than solar generation in previous intervals.[32] Even using this simplistic forecast, the "drop" between forecast and actual generation was less than 16.8% of installed capacity in 99% of intervals (i.e., in all but 166 of the 16,573 intervals with non-zero solar generation). If additional data were available – for example, weather forecasts showing that cloud banks were likely to arrive within an hour – it is likely that a one-hour-ahead forecast could be significantly more accurate than this simplistic construct. Power Advisory is not suggesting that 99% is the appropriate risk threshold, or that that drops expressed as a percentage of solar capacity are the appropriate basis for reserve requirements. The intent is only to illustrate

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[30] SACE/CCL Stenclik Direct, Exhibit B, p. 10.

[31] Power Advisory selected four of the NREL datafiles: "Actual_32.55_-80.85_2006_UPV_128MW_5_Min.csv", "Actual_32.95_-80.35_2006_UPV_16MW_5_Min.csv", "Actual_33.65_-81.75_2006_UPV_32MW_5_Min.csv" and

"Actual_34.05_-80.85_2006_DPV_35MW_5_Min.csv". These sites were selected to be as close as possible to the "NREL Sites" shown in the attachment to DESC's response to Power Advisory's Interrogatory 13 "Please provide a map of DESC's service territory and indicate the location of these 8 solar sites and the four locations where NREL data was used." These may not be the specific sites used by Navigant, but Power Advisory's analysis of NREL's datafiles indicates that sites close to each other show very similar solar generation, adjusted for the assumed size of the facility. For each site, output was divided by the indicated nameplate capacity, and the results were averaged to give a single solar profile for 5-minute intervals. These 5-minute intervals were grouped into 15-minute intervals (four per hour). The analysis was done on these 15-minute intervals.

[32] The forecast was based on two factors: average solar generation in the period between 75 and 60 minutes before the forecast interval, and the change in generation between those two times of day in the previous week. For example, the forecast for 11:00 to 11:15 am on January 8 was a function of (a) generation between 9:45 and 10:00 on January 8, and (b) the ratio of generation between 11:00 and 11:15 on January 1, 2, 3, 4, 5, 6, and 7, and generation between 9:45 and 10:00 on those same seven days.

how using a different forecast period could have changed Navigant's results, even with no additional data.

Power Advisory Assessment

In Power Advisory's view, neither DESC's nor Navigant's analyses of solar intermittency provide good bases for estimating the quantity of additional reserves that will be required, likely resulting in significant overestimation of the amount of additional reserves required and the associated costs. DESC's analysis is based on changes in solar generation from one time interval to another, rather than on differences between forecast and actual solar generation for the same interval. Since the purpose of reserves is to address unexpected changes in supply and demand, DESC's analysis is simply not relevant.

Navigant's analysis was based on a comparison between forecast and actual solar generation, but their exclusive reliance on four-hour-ahead forecasts is overly simplistic and fails to conform with best practice. Recognizing that there is a cost associated with a greater forecast error and that this forecast error can be reduced if the forecast is made closer to real-time, as acknowledged by Dr. Tanner,[33] Power Advisory believes that using a four-hour-ahead forecast is overly conservative and contributes to a need for higher reserves than would be required under an appropriate application of best practices.

Power Advisory recommends to the Commission that this issue be evaluated in greater detail during the independent study recommended in Act 62 to evaluate the integration of renewable energy and emerging energy technologies into the electric grid.[34] We do not believe that DESC's or Navigant's analyses of solar intermittency provide appropriate bases for determining additional requirements for flexible reserves.

2.3 Risk Threshold

There is some confusion in DESC's testimony about the exact level of risk used by Navigant in determining required reserve levels. According to Navigant's report, their reserve levels were sufficient to cover all possible drops: "For each solar penetration scenario, the maximum expected drop in solar generation for each year was used to determine the extra operating reserves that

[33] DESC Response to Power Advisory First Set of Interrogatories, #16 (d), p.21.

[34] Act 62. Section 58-37-60. "Independent study to evaluate integration of emerging energy technologies. The commission and the Office of Regulatory Staff are authorized to initiate an independent study to evaluate the integration of renewable energy and emerging energy technologies into the electric grid for the public interest. An integration study conducted pursuant to this section shall evaluate what is required for electrical utilities to integrate increased levels of renewable energy and emerging energy technologies while maintaining economic, reliable, and safe operation of the electricity grid in a manner consistent with the public interest."

need to be held to ensure that the reserve requirements are met."[35] In his rebuttal testimony, Dr. Tanner described it somewhat differently:

> "Navigant's analysis did not use the absolute maximum in potential solar undergeneration to estimate the amount of reserves that need to be held. In order to avoid the most extreme events in the data set, the analysis used a threshold of rounding to 1%."[36]

Regardless of whether Navigant's specific risk threshold was 0% or 1%, no explicit basis for it was provided in their report. As Mr. Horii notes:

> "When evaluating the need for additional operating reserves for DESC, Navigant does not perform any balance of risk and cost in the Integration Study. Nor does the Integration Study seek to maintain a specific level of risk previously deemed reasonable. Instead, the Integration Study assumes that solar generation will drop from its forecast level to its minimum output level based on forecast error information from the NREL. This assumption essentially places an infinite value on the cost of unserved energy, and results in integration costs that are likely higher than what would have been estimated had an actual risk-based analysis been performed by DESC. The balancing of costs and risks is a fundamental principle of electricity resource planning."[37]

Dr. Tanner responded to this as follows (including the statement quoted above about Navigant's risk threshold):

> "Q. … Mr. Horii suggests that DESC failed to conduct an analysis that balances risks and costs to determine the amount of operating reserves needed as a result of variable solar resources. Do you agree?
>
> A. No. Navigant's analysis did not use the absolute maximum in potential solar undergeneration to estimate the amount of reserves that need to be held. In order to avoid the most extreme events in the data set, the analysis used a threshold of rounding to 1%. This threshold was chosen specifically to balance the risk reduction vs. the cost of holding the additional reserves needed to integrate the solar generation. This is very far from an analysis of what it would take to mitigate all risks. In electric system operations, 1% can be a very meaningful risk."[38]

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[35] DESC Tanner Direct, Exhibit MWT-2, p. 25.

[36] DESC Tanner Rebuttal, p. 3, lines 15-18. The word "round" and variations on it ("rounded", "rounding", etc.) do not appear in Dr. Tanner's Direct Testimony of which Navigant's report is an exhibit.

[37] ORS Horii Direct, p. 12, lines 13-21.

[38] DESC Tanner Rebuttal, p. 3, lines 9-21.

However, no evidence was provided to quantify that risk. Mr. Stenclik states:

> "Rather than a grid outage event and customer disruption, a shortfall could lead to a potential violation of NERC standards and a potential fine. This is an important distinction when evaluating the tradeoff between risks and costs associated with reserve requirements. If a grid blackout were feasible, there should be significantly less risk tolerance."[39]

Mr. Bell argues that:

> "It is not realistic to assume these drops will not coincide with a unit trip, unit forced outage, limited transmission interface, or unusually high loads. To the contrary, it is likely to only be a matter of time before such a coincidence occurs, and we are in a situation where solar variability results in a generation shortfall.
>
> To put this risk in perspective, consider that there is about a 32% probability (very significant) that at least one baseload or intermediate generating unit will be forced out during the year. With solar generating more than 50% of the hours in a year and cloud formations somewhere across the system almost every day interfering with solar output, there is a significant risk of an overlap of solar drops and base/intermediate generator outages."[40]

Whether such an overlap would be problematic would depend on the size of the drop. It is common practice for utilities to calculate the risk of two or more problems occurring simultaneously resulting in inadequate supply (this is called "Loss of Load Expectation" or "LOLE". DESC did not provide LOLE results or any other quantification of the probability that a generator outage would coincide with a large drop in solar generation below forecast levels resulting in either a loss of load, or in a violation of NERC standards.

A similar criticism applies to DESC's use of a 35% standard, the basis of which is that it covers 96% of drops. There is no analysis to support 96% coverage, rather than the maximum observed drop, or some lower metric, as the appropriate threshold that balances costs and risks.

As support for both DESC's and Navigant's additional reserves to cover solar intermittency, Mr. Bell points to DESC System Control's current operating practice:

> "DESC's actual operating practice requires additional reserves (40% of actual output) for solar intermittency. This is greater than but generally consistent with the 35% one-hour

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[39] SACE/CCL Stenclik Surrebuttal, p. 22, lines 5-9.

[40] DESC Bell Rebuttal, p. 4, lines 3-13.

> ahead value (35% of installed solar nameplate) used in the avoided cost studies and in line with the Navigant Study 4-hour drop probability table."[41]

However, DESC's testimony on their current operating practices did not refer to a specific risk threshold, or to any explicit comparison of the cost of insufficient reserve levels to the cost of maintaining additional reserves. When asked "when did you first implement that assumption or that rule of thumb?", Mr. Hanzlik responded "I think over time it's -- it's [evolved] into that number."[42] Mr. Stenclik states:

> "Mr. Bell's rebuttal states that current operating practices include reserves to cover 40% of solar output. This is the first time where this information is stated by DESC in this docket and it appears to be a very recent development. The very recent imposition of increased reserve requirements lends further support to the need for additional study and operational experience prior to imposing a VIC. Adding contractual costs based on reserve requirements that have not been thoroughly established and vetted is premature and would be adding a real cost based solely on a simulated or very newly imposed reserve requirement."[43]

Power Advisory Assessment

In Power Advisory's view, none of the three standards used by DESC to determine the additional reserves attributable to solar generation (35% of nameplate capacity for the avoided cost calculations, up to 32% of installed capacity for the VIC calculations, and DESC System Control's 40% of forecast generation) have been adequately justified as a reasonable balance between costs and risks. We recognize that this isn't a simple or straight forward analysis, but believe that greater analytical rigor is required than DESC has employed to ensure a reasonable trade-off between reserve costs and risks.

2.4 Constant Reserve Levels

A third problem with DESC's solar integration cost estimates is that they were not modelled in ways that are consistent either with DESC's current operating practices or with industry-wide best practices for estimating solar integration costs. As discussed above, DESC's current practice is to

[41] DESC Bell Rebuttal, p. 7, lines 12-16.

[42] Hearing Vol. 1, p. 237, lines 1-7 page 54, lines 18-24 (DESC Hanzlik). The transcript shows "involved" but the questioner's response on line 12 interprets Hanzlik's answer as "evolved."

[43] SACE/CCL Stenclik Surrebuttal, p.13 lines 4-11.

maintain additional reserves equivalent to 40% of their forecast of solar generation as it varies during the day.[44]

Unlike DESC's actual practice, the simulations used to estimate solar integration costs did not vary reserve levels in proportion to solar generation. Rather, DESC's simulations to estimate avoided costs kept reserve levels constant at 35% of nameplate capacity in all solar generating hours[45] (i.e., with no reserves at night). Mr. Horii states:

> "In my direct testimony, I express concern over holding the higher reserves "in the evening or early morning" (Horii Direct, p. 23). Those are times when system loads can be high and solar output low. Since the solar output expected in the evening or early morning hours would be lower than at midday, there would be much lower downward output risk during those hours than during the middle of the day. Therefore, a higher level of extra daytime operating reserves would potentially overestimate the costs that would actually be needed to maintain system reliability during those hours."[46]

Navigant's simulations to estimate the VIC went even further, maintaining constant levels of reserves in all hours of the day, including nighttime.[47] Navigant did make some post-modeling adjustments for day-to-day variations in reserve requirements:

> "... the analysis calculated integration costs for the All Solar Case using the following proportions of days in which these levels of reserves must be maintained:
>
> - All Solar level of reserves is needed 38% of the days
> - Intermediate level of reserves is needed 51% of the days

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[44] Hearing Vol. 1, p. 214, lines 6-14.

[45] DESC Neely Direct, p. 10. "Solar generating hours" is not explicitly defined, but Mr. Stenclik estimates that it includes 4,000 to 4,200 (46-48%) of the 8760 hours in a year (Hearing Transcript, Day 2, p. 651, line 8; this seems reasonable. Mr. Bell, in his Rebuttal Testimony, states that "the additional reserve requirement [in the DESC Avoided Cost Methodology] is included as an hourly profile and is an accurate and required input in the avoided cost calculation" (p. 3, lines 7-9). However, there is no indication that this "profile" changes from hour to hour, other than being 35 MW during solar generating hours and zero in other hours.

[46] ORS Horii Surrebuttal, p. 11, lines 8-14.

[47] There are no direct statements in either Navigant's report or DESC's testimony that the same level of reserves was used in every hour, but there was also no mention of using different reserves amounts in different hours within the same case. Navigant discusses adjusting the modeling results to reflect different reserve requirements on different *days*, as discussed in the next footnote, but does not discuss any adjustment for different reserve requirements in different hours.

- Initial Solar level of reserves is needed 12% of the days"[48]

However, Navigant varied required reserve levels only between days, not hour-to-hour within the same day. Mr. Stenclik questions Navigant's approach:

> "Most troubling is that additional fixed solar reserve requirements were imposed 8,760 hours a year rather than being a function of the hourly forecasted solar generation, greatly overstating additional reserve costs."[49]

It is theoretically possible that the modeled cost of maintaining these extra reserves is low; Navigant states:

> "In most hours, especially overnight, DESC holds more than the minimum necessary reserves through their least-cost security constrained dispatch. This means that adding to the reserve requirement in the simulation does not materially influence the system operation in those hours."[50]

Dr. Tanner is more specific:

> "Thus, in the hours when the sun is not shining, the model shows that average reserves held on DESC's system are over 1,500 MW. By contrast, the planning model only required that 240 MW be held in the business-as-usual (i.e., non-solar) reserves case. This means that the additional reserves required for solar integration are not a binding constraint on the system in non-solar hours and thus do not materially impact the overall system operating costs or contribute to the calculation of the Variable Integration Charge ("VIC")."[51]

However, Dr. Tanner's conclusion (that the additional reserves required overnight "do not materially impact the overall system operating costs") does not logically follow from his statement that "average reserves held on DESC's system are over 1,500 MW" in non-solar generating hours. The estimate of VIC is not based on *average* reserves in all hours, but on the need to alter system

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[48] DESC Tanner Direct, p. 18, lines 5-10. The All Solar Case required 230 more MW of reserves than the Initial Solar Case. The Intermediate level of reserves is described as "between the All Solar and BAU requirements" (Tanner Direct Testimony, Exhibit MWT-2, p. 26, Footnote 9) but is not specified; 115 MW, or half of the All Solar Case requirement, is a reasonable estimate. Navigant's estimate of the VIC is therefore based on maintaining, on average, approximately 145 MW of additional reserves, which is 20% of the 708-MW difference in solar between the Initial Solar Case and the All Solar Case.

[49] SACE/CCL Stenclik Direct, p. 8 lines 18-20.

[50] DESC Tanner Direct, Exhibit MWT-2, p. 28.

[51] DESC Tanner Rebuttal, p. 6, lines 2-8.

operation in selected hours. Dr. Tanner's statement could only be true if none of those selected hours occurred at night. However, Mr. Hanzlik states:

> "The typical winter load curve begins with a morning peak just prior to sunrise when there is no solar output. During these early morning hours, solar is not available and DESC's non-solar generators are near maximum generation output levels while reserves are at the lowest level for the day."[52]

Navigant increased reserve levels in all hours, including these early morning hours with low reserve levels, even though there was no solar generation in these hours. It seems highly unlikely that this didn't have a material impact on their estimates of system operating costs.

DESC's response to these criticisms has been to point to Navigant's use of different reserve levels on different days. For example, Mr. Bell states:

> "Accounting for the difference between PROMOD's limitations and actual costs incurred, Navigant has made a logical and appropriate adjustment to the variable integration cost ("VIC") calculation to adjust for the difference between constant reserves and lesser amounts needed on 62% of days modeled."[53]

But such statements do not address the basis of the criticism, which is not about variations in reserve requirements from day to day (for example between a cloudy day and a sunny day) but about variations in reserve requirements from hour to hour (for example, between noon and midnight). As Mr. Stenclik notes:

> "Finally, the blending method suggested by Dr. Tanner to account for this is not standard industry practice. Production cost modeling tools such as GE MAPS and PLEXOS have been used for many, if not most, of North America's largest variable renewable integration studies and are capable of simulating hourly reserve requirements. Hourly simulation of reserve requirements is a standard approach implemented in renewable integration studies and the Cost of Variable Integration Study should be no different."[54]

While the above criticisms apply only to Navigant's simulations, DESC's avoided cost simulations could also be overstating solar integration costs, even though they did not maintain additional reserves overnight. Mr. Horii states:

> "In my direct testimony, I express concern over holding the higher reserves "in the evening or early morning" (Horii Direct, p. 23). Those are times when system loads can be high and

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[52] DESC Hanzlik Rebuttal, p. 12, lines 16-20.

[53] DESC Bell Rebuttal, p. 3, lines 3-6.

[54] SACE/CCL Stenclik Surrebuttal, p. 12, lines 10-16.

solar output low. Since the solar output expected in the evening or early morning hours would be lower than at midday, there would be much lower downward output risk during those hours than during the middle of the day. Therefore, a higher level of extra daytime operating reserves would potentially overestimate the costs that would actually be needed to maintain system reliability during those hours."[55]

Power Advisory Assessment

Both DESC and Navigant maintained high reserve levels even when solar generation was modeled to be low. It is likely that this contributed to over-estimation of the cost of maintaining additional reserves, because many of the hours when reserve levels are low (and the cost of maintaining additional reserve levels is therefore likely to be high) occur in the early morning when there is little or no solar generation. In Power Advisory's opinion, DESC has not provided convincing evidence that holding constant levels of additional reserves, either in all hours (Tanner's VIC analysis) or in all solar generating hours (avoided cost analysis), does not significantly overstate solar integration costs.

2.5 Alternative Mitigation Options

As Navigant points out, there are two ways to maintain reserve requirements:

1. Operate the existing system differently so that there are more operating reserves.
2. Procure quick-start resources such as battery storage or CT gas units that will be able to provide reserves even when offline.[56]

Navigant considers three types of such resources: quick-start combustion turbines, lithium-ion batteries with one hour of storage, and lithium-ion batteries with two hours of storage. For each, Navigant estimates its capital costs (ranging from $700 to $1,000/kW), calculates the amount of each that could be purchased at the same cost incurred by carrying more reserves (ranging from 75 to 110 MW), compares those amounts to the additional reserve requirements (which Navigant assumes to be 230 MW for a tranche of approximately 700 MW of solar, as discussed above, and concludes that "None of these capacities would be sufficient to meet the additional reserve requirements of the solar generation."[57] Navigant states "It does not currently seem cost-effective for DESC to add resources solely to provide the needed reserves."[58]

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[55] ORS Horii Surrebuttal Testimony, p. 11, lines 8-14.

[56] DESC Tanner Direct, Exhibit MWT-2, p. 28.

[57] DESC Tanner Direct, Exhibit MWT-2, p. 30.

[58] DESC Tanner Direct, Exhibit MWT-2, p. vii.

Mr. Stenclik, among others, has several issues with this approach. The first is that

> "… the resources were evaluated "solely" to provide reserves. A battery storage asset, or other new technologies, can provide multiple benefits to the system and should be evaluated in a more holistic way. These services could include firm capacity benefits, energy or energy arbitrage benefits, transmission and distribution deferral, and environmental benefits. Evaluating only reserve provision limits the ability for the resources to be economic based on multiple value streams."[59]

Navigant itself acknowledges the validity of this in a footnote, stating "it may be cost-effective to add resources for other purposes such as energy or capacity that have the added benefit of adding reserves to the systems that would reduce overall operating costs."[60]

Mr. Stenclik's second concern is that:

> "the Variable Integration Study did not evaluate other potential technologies and operating strategies, including new demand response, combined cycle upgrades, and discounting of solar forecasts."[61]

Mr. Raftery took issue with an earlier version of Mr. Stenclik's statement about demand response, noting:

> "the Company has conducted an extensive investigation into the possibility of relying on additional demand response programs to reduce peak demand … The study determined that there are no new cost-effective programs that the Company can add that will assist to mitigate the winter peak."[62]

Mr. Stenclik's original statement was "DESC did not include existing demand response resources to the full extent possible … DESC did not evaluate the potential to reduce ratepayer costs … by implementing new demand response."[63] Although Mr. Stenclik wrote "DESC", that section of his testimony was about "the Cost of Variable Integration study DESC has presented in the Cost of Variable Integration analysis"[64] – i.e., Navigant's VIC study. Navigant's study does not mention demand response or the other resources that Mr. Stenclik lists. Moreover, the fact that demand

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[59] SACE/CCL Stenclik Surrebuttal, p. 13, lines 2-8.

[60] DESC Tanner Direct, Exhibit MWT-2, p. 30, footnote 13.

[61] SACE/CCL Stenclik Surrebuttal, p. 13, lines 18-20.

[62] DESC Raftery Rebuttal, p. 3, lines 17-19 and p. 4, lines 2-4.

[63] SACE/CCL Stenclik Direct, p. 9, lines 9-16.

[64] SACE/CCL Stenclik Direct, p. 8, lines 1-2.

response has not been found to be cost-effective for meeting winter peak demand does not mean that it would not be cost-effective for providing reserves. Mr. Stenclik states:

> "[Peaking] demand response is fundamentally different than demand response for operating reserves as it typically requires at least 4-hours of customer load interruption. Demand response for operating reserves can be much shorter, only required until the next unit is turned online. This type of demand response has been introduced commercially at other utilities for variable renewable integration. Evaluating a study across a 13-year horizon without including new demand response resources as a candidate option overstates the cost of providing reserves, especially in future years."[65]

Mr. Stenclik's third concern is that "DESC did not evaluate the potential to reduce ratepayer costs through participation in a larger balancing area."[66] Mr. Bell responded:

> "Assuming a coordinated approach to solar intermittency is workable, it will require the agreement of multiple utilities and will involve quantifying and sharing the resulting costs. The success or value of such an approach cannot be assumed at this time and is beyond the scope of the current proceeding."[67]

Mr. Stenclik acknowledges the complexities of reserve sharing, but he disagrees with basing the solar integration costs on the assumption that DESC is effectively an "island":

> "Reserve sharing and coordination is the economically responsible behavior for the ratepayer, regardless of the market structure. While this type of coordination will undoubtedly take time to develop, it is certainly reasonable during the 13-year study horizon evaluated.
>
> I will add that this coordination does not necessarily require a reserve sharing agreement. By simply increasing bilateral energy transactions with neighboring utilities, DESC can "free up" their own generation (allowing their generators to back down to lower loading levels) to provide reserves instead of energy. There is already a long history of these energy transactions and it is a regular part of DESC's operations. This mitigation could be introduced today."[68]

Power Advisory Assessment

In Power Advisory's opinion, Navigant and DESC did not adequately evaluate alternative means of ensuring adequate reserves. It is impossible to determine, based on the evidence submitted, whether combustion turbines or batteries would be cost-effective if other value streams were

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[65] SACE/CCL Stenclik Surrebuttal, p. 22, lines 2-9.

[66] SACE/CCL Stenclik Direct, p. 9, lines 14-15.

[67] DESC Bell Rebuttal, p. 12, lines 19-22.

[68] SACE/CCL Stenclik Surrebuttal, p. 8, lines 11-20.

considered; if demand response targeted at providing flexible reserves appropriate for solar integration would be cost effective; or how likely it is that some kind of reserve sharing for solar integration will occur at some point over the period for which these rates would apply.

2.6 Integration Charge Conclusions

In Power Advisory's opinion, DESC's proposed values for the solar VIC, and solar integration costs embedded in its proposed avoided costs, are insufficiently supported by the evidence.

- The data and analysis on which solar intermittency risks are estimated are inappropriate, being based either on actual changes in solar output over time (rather than on a comparison of forecast and actual output for the same time period) or on a four-hour-ahead forecast that is inconsistent with the timeframe under which reserves would be dispatched (which may be four hours some of the time, but will often be much shorter).
- It is unclear whether the risk thresholds implicitly used in the estimates of solar integration costs are appropriate, because they have not been justified either by a loss of load probability calculation or by a comparison of the costs that would be incurred if reserves were insufficient vs. the costs of maintaining additional reserves.
- The modelling of additional required reserves for both the VIC and avoided costs is significantly different from DESC's actual practices for establishing reserves. DESC's actual practice is to base reserve levels on forecast solar generation, which means no increase in reserve levels at night and small increases in the early morning when solar generation is low. In contrast, both sets of simulations increase required reserves based on installed capacity (not forecast generation) in many hours beyond what is reasonably necessary, including nighttime hours (Navigant only) and hours with low solar generation (both). DESC asserts that this has no impact on the modeling results, but has not provided convincing evidence to support this claim. In Power Advisory's estimate, the modeling results are likely to include at least some hours with little or no solar generation but with significant additional costs attributed to solar generation.
- There has been inadequate consideration of alternative ways of providing additional reserves, such as combustion turbines or batteries which might be cost-effective when multiple revenue streams are considered in addition to those from providing reserves; demand response targeted at solar integration; and reserve sharing with neighboring utilities at least toward the end of the study period.

Mr. Stenclik states:

> "The independent renewables integration study authorized by recent South Carolina legislation would allow for a more transparent and accurate calculation of integration cost that includes stakeholders and additional technical experts."[69]

Given the lack of evidence to support DESC's estimates of solar integration costs, Power Advisory recommends that a cost study be undertaken as part of the independent study recommended in Act 62 to evaluate the integration of renewable energy and emerging energy technologies into the electric grid (as mentioned earlier).

Mr. Stenclik recommends that for now, no VIC should be charged:

> "The Commission must consider whether any integration charges are just and reasonable. Given the significant problems with the Dominion Cost of Variable Integration study approach and analysis, as outlined in my testimony and attached report, the Commission should not approve Dominion's proposed variable integration charge. The utility should revise its approach to address the problems identified and hold off on any integration charge until these concerns have been addressed and the utility has gained more operational experience, so that actual charges are not based solely on flawed simulations."[70]

Power Advisory does not support this recommendation. Power Advisory notes that a number of the parties in the DEC / DEP proceeding reached a settlement that accepted a solar integration charge of $1.10/MWh for DEC and $2.39/MWh for DEP. Based on this Power Advisory is reluctant to recommend that there be no solar integration charge.

Mr. Horii presents an alternative: temporarily use $2.29/MWh as an estimate of the cost of solar integration, using it both as the VIC and as the solar integration cost embedded in avoided cost-based rates:

> "For the value of solar integration, or "VIC," I find that the Navigant VIC study is overly risk averse in determining the need for additional operating reserves to account for the intermittency of solar generation. The Navigant study is overly risk adverse by focusing on just solar generation and not considering the totality of risk that involves all generation, transmission, and customer demand deviations. The Navigant study also overstated operating reserve needs by holding reserve levels constant over all hours when solar is operational. While I was not able to correct for the second problem, I was able to use Navigant's data to estimate VIC costs using a more reasonable level of additional operating reserves. By using my more reasonable level of additional operating reserves, the VIC drops from $4.14 per megawatt-hour to $2.29 per megawatt-hour, which is

[69] SACE/CCL Stenclik Surrebuttal, p. 22, lines 4-5.

[70] SACE/CCL Stenclik Direct, p. 10, lines 16-23.

> comparable to the solar integration cost proposed by Duke Energy Progress in Docket Number 2019-186-E.
>
> I, therefore, recommend in my surrebuttal testimony that avoided costs for solar QFs and solar-with-storage should start with Dominion's avoided energy cost for solar resources that exclude any additional operating reserves. My recommended VIC should then be subtracted from these avoided energy costs to arrive at avoided energy costs for solar that reflect a reasonable estimate of integration costs for solar." [71]

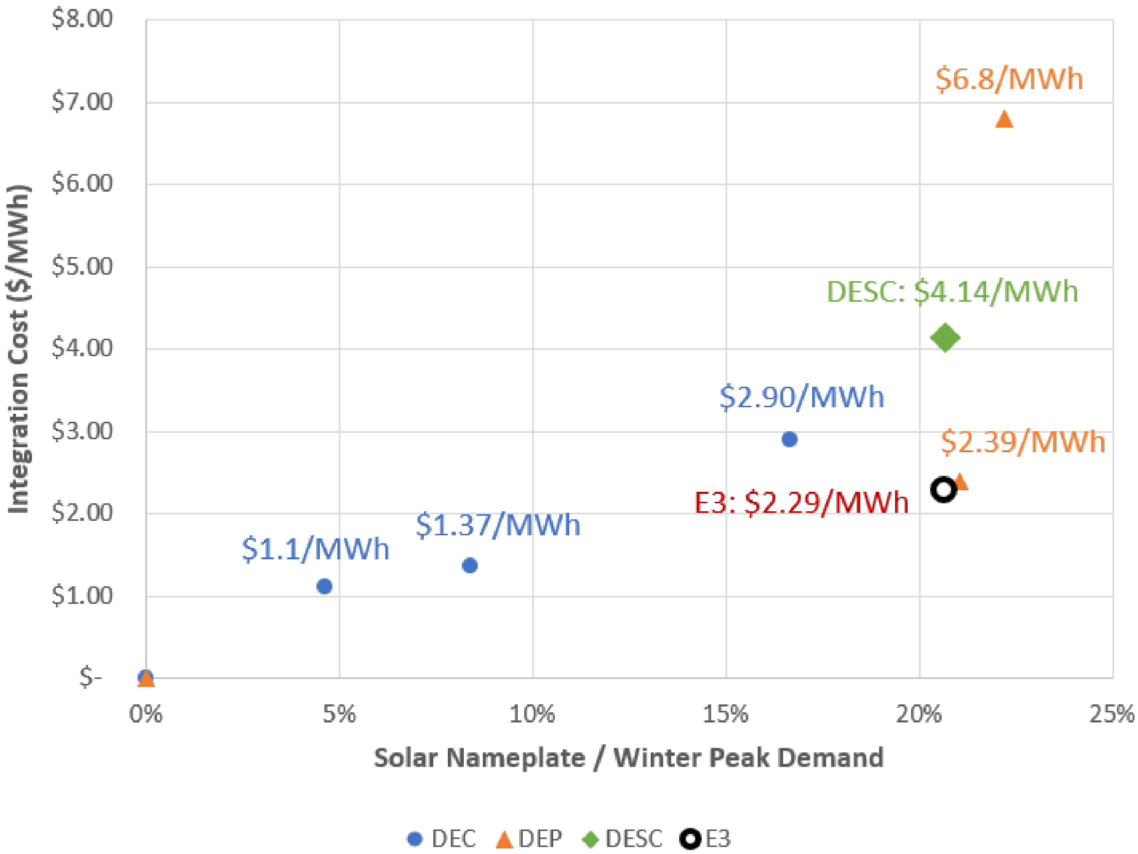
Power Advisory agrees with Mr. Horii's approach of developing a reasonable interim estimate of solar integration costs, using it as the VIC, and also using it to adjust the avoided cost-based rates – i.e., start with avoided costs that do not reflect solar integration costs, than subtract from them the same solar integration cost estimate used for the VIC. We do not support the specific calculations he used to arrive at $2.29/MWh, because it is based on Navigant's analysis, which is flawed in several ways, only one of which Mr. Horii attempts to correct. However, its magnitude is reasonable compared to the other solar integration costs proposed. Mr. Horii compared the E3 adjusted value and DESC proposal to the values for DEC and DEP in their respective dockets 2019-185-E and 2019-186-E (see Figure 2). Horii states that this figure:

> "…shows that my adjusted integration cost is very close to the value for DEP, and below the highest value for DEC. I believe the DEP result, however, is far more applicable to DESC than DEC. DEC has a higher percentage of coal and nuclear generation and lower percentage of natural gas generation than DESC and DEP. This would result in less flexibility for DEC and higher integration costs, all other things being equal. … The comparison to the DEC and DEP systems is useful because they are neighboring utilities subject to similar weather patterns. In addition, both DEC and DEP have seen significant, yet different solar penetration, which provides a useful comparison of estimated integration costs as a function of relative penetration levels."[72]

[71] Hearing Vol 2, p. 689 line 19 to p. 690 line 14 (ORS Horii).

[72] ORS Horii Direct, p. 19-20.

Figure 2. Renewable Integration Costs Proposed in South Carolina[73]



As an interim measure, until such time that the integration study has been completed and the results implemented, Power Advisory recommends using Horii's estimate ($2.29/MWh) as the VIC, and adjusting DESC's other solar rates (including PR-1, Avoided Cost and DER rates) to remove DESC's embedded integration costs and replace them with the same amount ($2.29/MWh) for all periods under consideration.

[73] Ibid.

3. STANDARD OFFER AND AVOIDED COST METHODOLOGIES

3.1 Defining Avoided Costs

Act 62 defines "avoided cost" as "…the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[74] DESC Witness Neely also notes this definition in his amended direct testimony.[75] The Act also directs that:

> "each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment."[76]

3.2 Avoided Cost Risks

DESC highlights the consumer risks posed by establishing avoided costs that ultimately prove to overstate actual incremental energy and capacity costs. To the extent that actual avoided costs are lower than projected avoided costs, ratepayers would be paying higher costs than if there were no QF contracts at these fixed prices. Conversely, if actual avoided costs are higher than projected, ratepayers would benefit from these fixed price QF contracts.

In support of this overpayment risk, DESC witness Kassis cites that FERC found from its 2016 PURPA technical conference that "allowing QFs to fix their avoided cost rates at the time a LEO is incurred has resulted in overpayments as energy prices have generally declined over the years, leaving the fixed energy portion of the QF rate well above the purchasing electric utility's actual avoided energy costs at the time of delivery."[77]

A shorter contract term is discussed as a primary way to mitigate some of the overpayment risk. That is the argument made by Kassis.[78] Notably, the proposed 10-year avoided cost determination consistent with Act 62 in this proceeding is significantly shorter than the historic PURPA contracts of 15 to 20 years that are offered as examples of overpayment. The time between LEO establishment, when avoided costs are fixed, and commercial operation also factor into the risk

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[74] 16. U.S.C. Section 824a-3(b); (d).

[75] DESC Neely Direct Amended, p.3 lines 3-6.

[76] Act 62. Section 58-41-20 (B) (3)

[77] DESC Kassis Rebuttal p.12-13 (168 FERC ¶ 61,184, p.27).

[78] Hearing Vol 1, p.63 (DESC Kassis) and DESC Kassis Rebuttal, p.13.

of overpayment. The shorter the period, the lower the risk that the costs do not reflect the systems avoided costs. Furthermore, the avoided costs are to be updated every two years with the idea that no payment to a QF starts at a rate that is more than two years old. (DESC's proposed commercial terms and standard forms are discussed in Chapter 4).

SBA's Hamilton Davis argues that the risks to ratepayers that the Commission should consider "are not limited to inaccurate avoided energy rates and extend to utility development and ownership of other generating resources, against which SPPs provide a significant risk hedge."[79] SBA Witness Burgess offers the cancelled VC Summer nuclear Units 2 and 3 as an example of the risks of conventional generation and notes that payment to QFs is performance-based which protects customers from construction risks.[80] Together, the SBA witnesses acknowledge that there is a risk of overpayment, but assert that there are additional consumer risks posed by utility generation investment that should be weighed.

Power Advisory also notes that DESC's calculated avoided costs are substantially lower than the avoided cost rates that have historically been paid to solar QFs in South Carolina. With lower established avoided cost rates, the risk and potential magnitude of overpayment is reduced. Underlying factors, such as forecast fuel prices, in particular natural gas prices, may further mitigate the risk. The primary driver of the declining energy prices that have resulted in overpayments under PURPA contracts is low natural gas prices. While further declines in natural gas prices are possible, this is expected to be less of a factor in future years.

3.2.1 *Implications of QF Market Size*

The amount of long-term QF contracts is one driver of avoided cost risk. The larger the amount of long-term contracts, the greater the chance for over or underpayment and resulting impacts on ratepayers.

Over the past two years, the drop in avoided costs paid to solar QFs in South Carolina has been dramatic. DESC indicated that avoided cost rates paid to solar QFs calculated in this proceeding are 40-60% lower than prices from just one year ago in 2018 and the rates in 2017 were about 50% lower than those in 2018.[81] DESC Witness Neely said that no PPAs have been signed under the 2018 rates and he expects that no PPAs will be signed for the rates set out in this proceeding.[82]

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[79] SBA Davis Direct, p.7.

[80] SBA Burgess Direct, p.14-15.

[81] Hearing Vol. 1, p.335 lines 1-23 (DESC Neely).

[82] Hearing Vol. 1, p.338 lines 8-23 (DESC Neely).

3.3 Rate Impacts

There was disagreement over whether ratepayers would stand to benefit or lose from the avoided costs calculated in this proceeding that would be paid to QFs. JDA and SBA testified that currently, the avoided costs are historically low and will likely rise in the future, thereby benefiting ratepayers should DESC lock in contracts now with QFs. At the heart of this discussion was gas prices. JDA Witness Chilton indicated that the EIA expects gas prices to almost double over the next 15 years and to triple over the next 30 years, which would drive avoided costs higher.[83] She went on to say at the hearing: "long-term PPAs entered into with QFs, at currently relatively low avoided costs, would protect the ratepayers of South Carolina by giving them the benefit of a locked-in low price."[84] Similarly, Mr. Levitas said at the hearing, "I think there's every reason to believe that locking in rates now at these very low rates is going to be extremely good for ratepayers over a long period of time."[85] In response, DESC Witness Neely said forecasts are not certain and indicated that it is entirely possible that gas prices triple over the next 30 years or drop by 50% over the next 30 years.[86] However, DESC Witness Neely acknowledged that if the gas prices go up as the EIA predicts that it is in the ratepayers' interest to lock in for a longer term.[87]

SBA Witness Adams pointed to the risk of higher natural gas prices and the risk ratepayers face of paying for costs stemming from the utility abandoning a project, which it doesn't face with a QF:

> "The evidence will show that these longer-term PPAs actually protect customers. Risks – they protect customers from risks that natural gas prices are going to rise. All the risks that come with a utility's decision to build its own generation plant -- cost overruns, delays, possibility that the utility will invest billions in a project that's abandoned – all of those are not borne by the ratepayers from a QF development. QF contracts insulate ratepayers from all these risks."[88]

Mr. Levitas noted the possibility of a carbon tax on the horizon which would drive prices higher, stating: "I think you should assume that there is a very high likelihood… sometime over the life of the horizon that you're planning for here, that the carbon and greenhouse gas implications of

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[83] JDA Chilton Direct, p.8 lines 1-5.

[84] Hearing Vol. 2, p.483 lines 14-18 (JDA Chilton).

[85] Hearing Vol. 2, p.477 lines 6-9 (SBA Levitas).

[86] DESC Neely Rebuttal, p.16 lines 7-14.

[87] Hearing Vol. 1, p.366 line 24 (DESC Neely).

[88] Hearing Vol. 1, p.25 lines 7-18 (SBA Adams).

natural gas exploration and development and transport, in addition to the combustion impacts, will come under significant regulation."[89]

3.4 Avoided Energy Costs

DESC estimated avoided energy costs for both solar and non-solar QFs using a simulation model of their system. In general, the intervenors did not indicate an issue with the overall framework, but as discussed further below some did suggest certain assumptions were problematic and led to avoided cost estimates that were too low, particularly for solar generation.[90] Given the interest of many intervenors, avoided energy costs for non-solar facilities received relatively limited attention.

3.4.1 DESC Methodology and Results

DESC uses a Difference in Revenue Requirements ("DRR") methodology to calculate both the energy component and capacity component of its avoided costs. DESC Witness Mr. Neely notes that "This approach involves calculating the revenue requirements between a base case and a change case. The base case is defined by DESC's existing and future fleet of generators and the hourly load profile to be served by these generators, as well as the solar facilities with which DESC has executed a power purchase agreement. The change case is the same as the base case except that a zero-cost purchase transaction modeled after the appropriate 100 MW energy profile is assumed."[91] The long-run avoided costs are calculated from 2020 to 2029 and are divided into two groups of five years: 2020-2024 and 2025-2029.

As discussed, DESC provided separate avoided cost estimates for a solar QF and a non-solar QF. The solar estimate was developed using a solar profile to reflect an hourly production shape from a 100 MW solar facility, whereas the non-solar estimate was developed using a 'flat' 100 MW 24 x 7 block of incremental energy.

DESC used PROSYM for its analysis. The base and change cases are identical except for the zero-cost purchase transaction in the non-solar case, and the zero-cost purchase plus incremental operating reserves in the solar generation case. The avoided energy cost is the difference between the base case costs and the change case costs for each. As discussed in Chapter 2 above, the solar avoided cost calculations were modeled with additional reserves equal to 35% of the installed

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[89] Hearing Vol. 2, p.510 lines 10-16 (SBA Levitas).

[90] SBA Burgess Direct, p. 2 provides a summary of issues and ORS Horii Direct, p. 27.

[91] DESC Neely Direct, p. 7. Mr. Neely notes that this methodology was approved by the Commission in Orders No. 2016-297 and 2018-322(A).

solar capacity, during solar generating hours.[92] Issues with this aspect of DESC's methodology are discussed in that chapter.

DESC ran its model 10 times for each year and labeled these iterations of its model "seeds". This approach reflects uncertainty in certain assumptions such as generator availability due to forced outages and hourly demand patterns due to weather. It is an industry standard approach to reflect random elements in the system, though DESC did not make clear in the information provided what varied within each iteration. Each iteration of the model represents a possible outcome in terms of avoided costs and DESC estimated the avoided costs by averaging the 10 seeds. Again, this approach was not articulated but is apparent from the spreadsheets provided for modeling results.

DESC's results from this process are highlighted in Figure 3. The avoided energy costs for non-solar generation are grouped into 4 pricing periods within the standard offer, but are shown as an all-hour average in this figure for ease of comparison to solar avoided energy costs. The values in the figure are taken from modeling results files provided by DESC.

Figure 3. DESC's Proposed Avoided Costs [93]

	Avoided Costs - Non Solar ($/MWh)	Avoided Costs - Solar ($/MWh)
All Hours 2020-2024	$30.93	$16.76
All Hours 2025-2029	$36.46	$15.66

The intervenors largely accepted the overall methodology at a conceptual level, but indicated a number of specific concerns. Mr. Horii asserts that:[94]

- DESC overstated the amount of incremental operating reserves required to integrate 100 MW of solar.
- DESC used operating reserves rather than a potentially lower cost form of reserves to integrate solar.

[92] DESC Neely Direct, p. 10.

[93] DESC Response to ORS Utility Services Request #1-2 and #1-3. Data from files "Avoided Costs – Standard Offer.xls" and "Avoided Costs – Non-Solar.xls"

[94] ORS Horii Direct, p. 27

- DESC used flawed assumptions and produced inconsistent results in terms of the integration costs for solar that alternated from positive to negative integration costs annually.

Mr. Burgess argues that:[95]

- DESC assumptions and methodology were not transparent.
- DESC's selection of pricing periods is potentially biased against solar.
- DESC treated solar with storage inappropriately.[96]
- DESC's treatment of imports and exports raised concerns.

With respect to Mr. Horii's concern that DESC used flawed assumptions and produced inconsistent results, the concern was that the costs associated with higher reserves for integrating solar alternated from positive to negative. [97] Power Advisory has similar concerns as discussed below. DESC recognized an error in their results and addressed this concern, as stated in its rebuttal testimony and outlined in its hearing testimony.[98]

The issues that we believe warrant further discussion are outlined throughout the next sections of this chapter.

Power Advisory Assessment

The key issue in estimating avoided energy costs relates to integration costs and the solar avoided cost rates. DESC has assumed that it will need to carry 35% of installed solar capacity in incremental operating reserves, whereas a range of intervenors have indicated this results in is a large over statement of integration costs as discussed in Chapter 2. Notwithstanding this specific critique of DESC's approach, Power Advisory would expect very little impact on off-peak costs due to an increase of 100 MW of installed solar capacity. DESC results do not show this pattern.

Figure 4 and Figure 5 highlight this concern for two model iterations from results provided by DESC in 2027.[99] Seed 1 was selected as a model iteration that illustrates results that are difficult to reconcile with logical expectations. The graphs show the increase or decrease in system costs in $/MWh on the vertical axis, while hours of the day are on the horizontal axis. Note that the $/MWh costs in the graph are the change in total system costs, i.e. if hourly load was 5,000 MW at 4 am, a $4/MWh cost represents a $20,000 increase in energy costs in an hour with no solar

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[95] SBA Burgess Direct, p. 21-22

[96] Hearing Vol 1, p. 340 line 3 to p. 342 line 14 (DESC Neely). Neely states that the solar and storage rate has not been prepared but will be prepared by the end of 2019 as mandated.

[97] ORS Horii Direct, p.29-30.

[98] DESC Neely Rebuttal, pp. 6-7 and Hearing Testimony, October 14, 2019, pp.127-128 (Witness Neely).

[99] DESC Response to ORS Request #1-2, file "Avoided_Cost_seed1_Base.mrg" less "Avoided_Cost_seed1_Change.mrg". Winter is defined as November through March in the graphic, while Summer is defined as the remainder of the year for simplicity.

production. This graph is an hourly representation of the DRR methodology results as reflected by DESC's hourly data.

[redacted]

As illustrated, in winter months particularly, Seed 1 has very high over-night costs associated with 100 MW of incremental solar capacity, a time when there would be no solar output. While DESC did not provide hourly data for the iterations of the model without incremental operating reserves, the hourly results with the solar resources appear to show that additional solar generation results in very large overnight costs. This seed does not reflect a similarly large reduction in avoided energy costs in hours with solar production, especially during winter hours (defined as November through March within this analysis).

Power Advisory cannot reconcile this pattern of very high overnight costs when there should be no incremental ancillary services costs from solar generation (as there would be no solar output) against minimal on-peak avoided energy costs. [100] Notably, in this iteration of the DESC model,

[100] DESC Neely Direct, p. 10. States that reserves are added only during solar generating hours.

[redacted]

Seed 2 is another iteration of the model that shows above average avoided costs for solar generation but still shows significant incremental costs in hours with no expected solar generation. For example, in the winter months the model shows [redacted] Minor changes in avoided costs overnight are reasonable due to small changes in timing of storage decisions and unit commitment, but it is unclear what would trigger large incremental costs in hours when solar generation is not operating.

[redacted]

Comparison of the individual model runs within the files noted also raises concerns with the modeling for solar generation.[102] As noted, DESC performed 10 iterations of its models to determine the avoided cost via the DRR methodology. The results for the solar generation avoided cost estimates appear to demonstrate an extreme level of modeling uncertainty around the estimated solar avoided costs. For example, the model results indicate that when incremental

[redacted]

[102] Power Advisory has reviewed similar data for the non-solar analysis and does not have concerns.

reserves are carried to integrate solar, in some iterations solar generation has avoided energy costs below [redacted]

[redacted]

This level of uncertainty calls into question the overall reliability of the results for solar generation. Given that the main fundamental supply and demand assumptions are identical between model seeds,[103] avoided energy costs from solar generation ranging from -$6/MWh to $30/MWh is concerning. At a minimum, these results should be examined in much greater detail than was possible given the timing and lack of supporting data provided by DESC. Power Advisory does not have similar concerns with the non-solar modeling.

Second, the fact that individual seeds vary so widely with constant assumptions raises the possibility that the results are highly sensitive to assumptions such as unit commitment and storage treatment, as well as other less obvious assumptions. Clarity around the impact of key drivers is necessary to properly evaluate the reasonability of the results. To the degree that the modeling results reflect such variability we would expect that the factors that contribute to this variability would be explained in an effort to demonstrate the reasonableness of these results.

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[103] In Power Advisory's experience and with the information provided in the filing, albeit minimal in nature, the fundamental assumptions (supply mix, fuel costs, annual load and unit characteristics) are understood to be identical across model seeds and only random factors drive the difference.

Finally, the results suggest a fundamental concern that cannot be addressed with the data as provided. Very high overnight costs associated with solar generation are counterintuitive. Incremental operating reserve costs should not be the driver as there is no solar generation in these hours and DESC has indicated reserves were only added during solar production hours. Other factors such as differences in unit commitment are a possible explanation, but accepting this as the driver would require much more information than available.

3.4.2 Transparency

Mr. Burgess suggested that DESC did not meet the transparency requirement of Act 62, while Mr. Horii did not mention transparency concerns but did note that more time to do more detailed analysis would be helpful. [104] [105] As stated in the legislation, "Each electrical utility's avoided cost filing must be reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission."[106] Mr. Burgess argues:

> "there are several aspects of DESC's avoided cost calculations and methodologies that are obscure and unexplained, both in Dominion's initial cost filings and in discovery responses. Dominion's filings are far less transparent than Duke's filings, which themselves were not models of clarity. As a result, there may be additional problems with methodologies and assumptions beyond the issues identified in my testimony below. Certainly it would be impossible to independently "verify" the reasonableness of Dominion's proposed rates based on the information that has been provided by the company. The issues on which there is a meaningful lack of transparency include (but are not limited to) the rationale for selection of peak hours and peak seasons as well as hourly avoided cost data and marginal cost data for the base and change case in DRR analysis."[107]

DESC disagreed with Mr. Burgess' assessment. Witness Neely states "I believe that Mr. Burgess' own testimony disproves his suggestion that DESC's avoided cost filings are not reasonably transparent. On page 21, line 17 through page 22, line 12 of his direct testimony, Mr. Burgess accurately describes the methodology used by the Company, which indicates that he understands and is aware of the methodology employed as well as its individual components and the underlying data. I would also state that DESC properly responded to all of SCSBA's requests for information."[108]

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[104] SBA Burgess Direct, p.22.

[105] ORS Horii Direct, p.6.

[106] Section 58 41 10 (J)

[107] SBA Burgess Direct, p.21, lines 4-14.

[108] DESC Neely Surrebuttal, p.21, lines 4-10.

Mr. Burgess argued that a high-level understanding is not sufficient to meet the requirements of the Act. He states:

> "I was able to describe my understanding of DESC's approach in general terms, because DESC provided a high-level explanation of its methodologies in its direct testimony (as it has historically done in previous dockets setting avoided cost). But that is not sufficient for Act 62, which requires enough transparency 'so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission.' As described in my direct testimony, there are many instances in which Dominion did not provide access to adequate data and modeling details to verify the reasonableness of specific methodological choices or inputs and assumptions used by DESC, or its subsequent findings. Additionally, key portions of DESC's analysis on integration costs were provided only one day before intervenor direct testimony was due, thus severely limiting my to analyze the results or serve discovery in a timely manner."[109]

Power Advisory Assessment

In Power Advisory's view, the DESC avoided cost filing did not fully provide a sufficient level of transparency "so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission."[110] For example, DESC provided avoided cost data in response to interrogatories and didn't identify the data structure or format, requiring a secondary interrogatory, which consumed valuable time in any already compressed schedule.[111] Although transparency improved throughout the proceeding, significant portions of the data were provided in a form that required substantial effort to digest. We would expect that basic data to support the avoided cost estimates could be provided as part of the initial filing.

In addition, there remain significant questions as noted in this chapter that cannot be answered with the information provided. While hourly avoided costs data was provided, other data required to fully vet the drivers of the avoided cost patterns outlined in this chapter were not provided. Therefore, we don't believe that DESC satisfied the transparency standard outlined in Act 62.

3.4.3 Technology Neutral Approach

DESC has proposed two distinct rates: one for solar generation and one for non-solar generation. As stated during the Hearing, DESC believes that the unique production profile of solar generation justifies a rate specific to solar generation.[112] In contrast, a technology neutral approach could

[109] SBA Burgess Surrebuttal, p.4-5.

[110] Act 62. Section 58-41-30. (J)

[111] DESC Response to SBA Request #2-1 and 2-2.

[112] Hearing Vol. 1, p. 315 lines 15-23 (DESC Neely).

define avoided cost values by time block and all resource types would be paid the same for energy produced in that time block.

Mr. Burgess suggests a technology neutral approach that values energy the same in a given time period regardless of the type of generator that supplied it. Mr. Burgess outlined that "This resource-specific approach raises significant concern about the ability of separate rates to properly represent the full suite of QF technological possibilities within the categories of "solar" and "solar-plus-storage." Singling out these resource categories and computing pre-determined avoided cost rates suggests that they each have rigid technological and performance specifications when in fact both "solar" and "solar-plus-storage" cannot be generalized as such."[113]

Mr. Burgess further states that a technology neutral approach could "be similar to the non-solar QF rate that DESC has proposed, but made available to all technologies. I believe such a "technology-neutral" rate would provide a better price signal to prospective solar and solar-plus-storage generators to target energy and capacity delivery during the times they benefit customers most."[114] Burgess also notes that this is the approach Duke has taken.

In the absence of a technology neutral approach, Burgess suggests an approach that provides a unique value to all possible configurations of solar and solar plus storage.[115]

DESC disagreed with both the proposal to develop a technology neutral rate, as well as with Burgess' alternative approach in the absence of a technology neutral approach. Specifically, Neely notes "Solar has a unique profile and therefore the true avoided cost of additional non-dispatchable solar can only be accurately captured using a solar specific avoided cost calculation. As well, the Form PPA tariff envisioned by Act No. 62 allows utilities to calculate resource specific avoided cost rates."[116]

Power Advisory Assessment

A technology neutral approach is more flexible and reflects actual value for customers in specific hours. The approach suggested by Burgess modeled on the non-solar QF contract is reasonable, though it may be necessary to develop a larger number of groupings to reflect value from generators with highly correlated profiles, such as solar. Power Advisory agrees with the concern that there are a large number of configurations that will result in materially different solar profiles

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[113] SBA Burgess Direct, p. 19-20.

[114] Ibid,, p. 20-21.

[115] Ibid., p. 21.

[116] DESC Neely Rebuttal, p. 20.

from new facilities, and as a result the DESC approach is potentially discriminatory because it is premised on a specific production shape that may not hold true for future facilities.

3.4.4 Selection of Pricing Periods

Burgess raises a concern that the grouping of hours is potentially biased against solar generation and that the data to support the groupings shown was not supported. [117] [118] Burgess also questions the result that avoided costs are higher during off-peak seasons, in contrast to typical expectations. This is supported with analysis of load shapes and load shapes net of solar generation. Burgess concludes by suggesting that hourly data on avoided costs and marginal costs should be provided.[119]

In Rebuttal Testimony, Neely indicates that Burgess' concerns are not valid as the selection of pricing periods applies only to non-solar generation. In his Surrebuttal Testimony, Burgess stated that data files provided by DESC do in fact group data into the four hourly pricing periods noted for solar generation.

Power Advisory Assessment

The pricing periods should be chosen to reflect discernable pricing patterns and underlying differences in avoided costs throughout the day. The use of broad pricing periods increases the risk that these periods are composed of times when there are consistent underlying differences in avoided costs, which would be better reflected in more narrow pricing periods. We recommend that DESC provide support for the pricing periods that it employs in its next avoided cost filing.

3.4.5 Avoided Energy Cost Conclusions and Recommendations

The data provided by DESC raises significant concerns with the modeling used to estimate avoided energy costs for solar generation. These concerns are driven in part by the approach of adding ancillary services to integrate solar generation, but it remains unclear why off-peak costs during hours with no solar generation are, in some cases, nearly as large (or even larger) than the on-peak avoided costs. The extreme range in the estimates across different iterations of the model is also problematic as the overall system assumptions are the same for each iteration of the model, and the range of outcomes is outside of what would be expected based on Power Advisory's experience.

Hourly data was only provided for the solar change case including incremental operating reserves. Based on the pattern of hourly avoided costs seen in the change case with incremental operating

[117] SBA Burgess Direct, p. 24

[118] SBA Burgess Direct, p. 24-28.

[119] Ibid., p. 27-28. Note that hourly avoided cost data was subsequently provided on a confidential basis.

reserves, it is important to understand the driver of overnight cost increases. With the data provided, it is not possible to determine if the ancillary services assumptions are driving the impact or whether other factors such as altered generation commitment patterns are driving the result. In either case, the results raise concerns with the approach both due to the pattern of hourly avoided costs and the extreme range of avoided costs across model iterations.

Given Power Advisory's view that the 35% of installed solar capacity reserve assumption is inappropriate (see Chapter 2 conclusions), Power Advisory recommends that the Commission undertake an independent renewables integration study, as authorized by Act 62. This will "allow for a more transparent and accurate calculation of integration cost that includes stakeholders and additional technical experts."[120] In addition, in subsequent avoided cost filings Power Advisory recommends that DESC be required to include avoided cost estimates as part of its initial filing and we would expect that it would provide evidence that highlights the key assumptions and where there are counterintuitive results (e.g., overnight negative avoided costs from solar) or extreme ranges in outcomes across model seeds that these be explained. In order to determine if the avoided cost estimates are reasonable, it is first necessary to understand what is driving the results outlined in this chapter.

Given our concerns with the avoided cost modeling and the relatively significant divergence in avoided costs from those projected for DEC and DEP, we are concerned that the avoided cost estimates presented by DESC are not reliable.[121] Given the lack of transparency with respect to the Company's avoided cost methodology and assumptions there aren't specific changes to the methodology and assumptions that we can recommend.

As an interim step and as noted in Chapter 2, until such time as the integration study has been completed and the results implemented, Power Advisory recommends adjusting DESC's solar rates – including PR-1, Avoided Cost and DER rates – to remove DESC's proposed integration costs and replace them with an integration cost of $2.29/MWh for all periods under consideration, based on a proposal by Mr. Horii.

3.5 Avoided Capacity Costs

There are two key areas debated on the value of capacity. First, there are methodological issues on the amount of capacity provided by solar resources. Second, several issues are related to the actual cost of capacity resources that would be avoided that impacts both solar and non-solar resources.

[120] SACE/CCL Stenclik Surrebuttal, p. 22, lines 4-5.

[121] Power Advisory acknowledges that caution should be exercised when comparing avoided cost estimates between two different companies and when doing so consideration needs to be given to differences in their resource mix and demand profile.

3.5.1 DESC Capacity Value Methodology

DESC and several intervenors disagree on the approach to determine the capacity value of solar resources. At issue is how much capacity solar QFs actually avoid. There are two basic approaches. The DESC approach assumes that DESC is a winter peaking system and the capacity value of a resource is a function of how much it generates during the peak winter hours. This is effectively a reserve margin approach that assumes if there is enough capacity to meet demand in the peak demand hour, there will be enough capacity in the rest of the year as well. The alternative approach is more probabilistic in nature and assesses how much an asset will be producing on an expected basis during 'critical' hours, where critical hours are influenced by both supply outages and high demand. This is known as the Effective Load Carrying Capacity (ELCC) approach.

DESC Witness Lynch provides an overview of the ELCC approach as applied by DESC. "There are basically three steps in calculating an ELCC value. The first step is to calculate the LOLH in the base case. The second step is to create a change case by combining the solar profile with the base system load profile to create an adjusted load profile net of the solar output and then recalculate an LOLH. The LOLH in the change case will be lower than in the base case indicating more reliability. In the third step, either the loads are increased, or the capacity is decreased in the change case until the LOLH matches the base case LOLH. The resulting adjustment in load or capacity is the ELCC value of the solar profile since it results in an equivalent LOLH value to the base case."[122]

A second approach employed by DESC is a reserve margin approach, which DESC asserts indicates that solar generation does not provide any capacity value for its system.[123] DESC argues that capacity needs are driven by winter peaks and solar does not provide any energy during these critical peak periods. DESC notes it has done significant work studying the capacity value of solar. In Mr. Lynch's Rebuttal testimony he stated "All three analyses represent thorough and detailed studies of the characteristics of solar generation and its impact on the Company's system load. All three support the same conclusion that solar does not avoid the Company's need for winter capacity, does not avoid any capacity costs, and therefore has a zero-capacity value. I do not consider this work overly simplistic; instead, it represents direct analysis of actual solar profiles and provides clear and irrefutable evidence that solar has a zero-capacity value on DESC's system."[124]

The essential finding Mr. Lynch relies on is that the combination of solar production timing and the timing of load peak hours do not align because the peak load hours are early morning in the winter. DESC suggests that unless a resource serves load in these peak hours, there is no capacity contribution because the company will still purchase capacity sufficient to meet its reserve margin

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[122] DESC Lynch Direct, p. 9.

[123] DESC Lynch Rebuttal, p. 2.

[124] DESC Lynch Rebuttal, p. 2.

target in the critical hours. On this basis, Mr. Lynch discounts entirely the value of the ELCC approach:

> "Unfortunately, it does not matter how good or bad the ELCC estimates are in summer. DESC needs capacity in the winter and solar does not provide capacity on early winter mornings before sunrise when the system peaks nor during peak hours on most non-summer days when the system peaks before sunrise or after sunset."[125]

ORS witness Horii suggests that the ELCC approach is the industry standard and more appropriately reflects capacity value of solar:

> "Therefore, I maintain the position that DESC's approach for avoided capacity cost is simplistic. This simplistic focus is reinforced by the Company's own rebuttal testimony that attacks the industry standard Effective Load Carrying Capacity ("ELCC") approach because the ELCC recognizes there is a value from solar capacity at times other than before sunrise (Lynch Rebuttal, pp. 4-5). While DESC's system may often peak before sunrise, the need for capacity also depends on the risk of generation or transmission outages, which can occur at other times of the day, therefore resulting in values for capacity at other times of the day."[126]

SBA Witness Burgess makes similar comments on the probabilistic nature of outage events. Mr. Burgess describes the DESC approach as "…somewhat akin to betting on a horse race. One strategy might be to put all your money on the front runner since that horse is more likely to win. However, another strategy might be to place a series of smaller bets on the second, third, and fourth ranked horses. Over the long-run the second strategy could have a similar or even greater payout. Diversifying one's "bets" in this way also serves to reduce the overall risk of the investment, as compared to a single large bet on the leading horse. Likewise, for resource planning, one could plan solely for the one peak hour of the year that has the highest probability of an outage (e.g. as DESC claims, this might correspond to January at 7 a.m.). However, this would ignore many other hours of the year that have smaller, but still meaningful probabilities of an outage. Covering these hours could have the same or even greater contribution to reliability from a probabilistic standpoint as addressing the single peak hours."[127]

Mr. Burgess expands on this point to suggest DESC's system has net summer peaks that are very close to the winter peaks and the relative importance of summer peaks versus winter peaks could easily change.[128] His evidence suggests the DESC approach overstates the degree to which only

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[125] DESC Lynch Direct, p. 11 lines 9-13.

[126] ORS Horii Surrebuttal, p. 10.

[127] SBA Burgess Direct, p. 47-48.

[128] SBA Burgess Direct, p. 50-52.

winter capacity has value on the system and therefore understates the capacity value of solar generation.

Mr. Burgess also provides evidence in support of using the ELCC approach, as it is a common approach, particularly in regions with large solar generation fleets.[129]

Based on the ELCC methodology, Mr. Horii suggests that solar should receive a capacity benefit of 11.8% of its nameplate capacity because there are already over 500 MW of solar operating in DESC territory. Given that solar adds progressively less capacity value as its installed base grows, Mr. Horii proposed that the ELCC value from 500 MW to 1,000 MW be used.[130] SBA Witness Burgess suggests solar could receive a capacity value of 24% based on the average capacity contribution of 1,000 MW of solar, as calculated by DESC under the ELCC approach.[131] DESC Witness Lynch states that because the company already has 1,048 MW of signed solar PPAs, even under the ELCC approach the appropriate value for solar capacity is 4%.[132]

Power Advisory Assessment

The ELCC methodology is industry standard and reflects a probabilistic approach to resource modeling. Power Advisory agrees with Mr. Horii and Mr. Burgess that solar provides capacity even in the event it does not generate during the system peak load hour because capacity shortfalls can occur in non-peak hours due to supply side issues. Reliability is a function of both supply and demand factors, and the approach outlined by Lynch does not reflect this. The fact that DESC has summer peak loads relatively similar to winter peak loads after the impact of demand response has been netted out, as outlined by Mr. Burgess, reinforces the approach that values capacity during all potential hours where there may be insufficient supply.[133]

Capacity value should therefore be estimated using the ELCC methodology. As raised by Mr. Lynch, DESC has over 1,000 MW of solar capacity under contract and therefore the capacity value of solar should be estimated assuming this capacity is already in place.[134] As noted, this provides a capacity value of 4% of installed capacity on the basis that 1,000 MW of solar have already executed a contract.

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[129] SBA Burgess Direct, p. 52.

[130] ORS Horii Direct, p. 37.

[131] SBA Burgess Direct, p. 59-60.

[132] DESC Lynch Rebuttal, p.11 line 12 to p. 12 line 8.

[133] SBA Burgess Surrebuttal, p. 11 paragraph 1-2.

[134] Ibid.

3.5.2 DESC Capacity Cost Methodology

The second key area of disagreement involves the approach used to estimate the actual value of capacity. In effect, DESC uses a methodology that intervenors suggest under-values capacity on a $/MWh or $/kW basis.

DESC states it has in effect two reserve margin targets for winter capacity. Its "base" reserve margin target is 14% and its peaking reserve margin target is 21%. Similarly, DESC as a base reserve margin target of 12% in the summer and a peaking reserve margin target of 14%.[135] DESC purchases capacity from lower cost resources such as market purchases or demand response to meet the "peaking" reserve margin requirements, whereas "base" requirements are meant with internal capacity such as generation development.

At issue is whether the avoided capacity cost should be estimated based on the cost of meeting peaking needs with a gas generator or with market purchases. The impact of this choice on avoided capacity cost is significant. Witness Horii estimates capacity costs more than three times higher for non-solar generation than DESC.[136]

> "The correction of the winter reserve margin and the consistent use of CTs to meet capacity needs has the largest impact. I also detected an error in the DESC model. The Company incorrectly used a 14% reserve margin in their model, which reduces the need for capacity, thereby reducing the value of QF capacity. A 21% reserve margin is DESC's stated reserve margin for evaluating the need for peak capacity (Lynch, p. 17), and also the reserve margin used for their resource planning, as shown on their Load and Resource Balance tables on pages 47-48 of their 2019 IRP."[137]

DESC disagrees with Mr. Horii and states that it uses a 14% reserve margin in estimating the capacity value of PURPA resources because it purchases low-cost and relatively short duration capacity to meet the 21% reserve margin. In effect, DESC uses a 14% reserve margin for base winter capacity needs and the incremental 7% margin is required for rare periods when cold weather increases peak demand above typical levels. This relatively rare capacity need is met by demand response (interruptible load) or market purchases, as an example.

As stated by DESC Witness Neely:

> "The low-cost capacity resources in the avoided capacity calculation were the same as those shown on pages 47 and 48 of the Company's 2019 IRP. These low-cost capacity resources could be purchased power or other types of low-cost resources such as interruptible load. These low-cost capacity resources were meant to provide needed

[135] DESC Neely Rebuttal, p. 9.

[136] ORS Horii Direct, p. 41.

[137] ORS Horii Direct, p. 40.

> peaking reserves for the top 10 to 20 days of highest capacity need each year. Because only half of the peak days would occur in the winter, it would be inappropriate to add a generating resource for the purpose of only covering generation needs for 5 to 10 winter peak days a year. Instead, the Company currently plans to only add generating resources to the resource plan when the winter reserve margin drops below the 14% level or the summer reserve margin drops below the 12% level. These costs accurately reflect DESC's forecasted costs and reflect an approach to system planning that minimizes costs to customers."[138]

Mr. Horii disagreed with this approach in his surrebuttal testimony and stated that the appropriate approach to meet even infrequent capacity needs remains a combustion turbine.[139] The rationale provided was that surplus capacity may not be available from other markets when needed, and savvy capacity providers would price short-term capacity at the avoided cost level of the buyer in any event. Finally, Mr. Horii notes that for consistency if the DESC approach is used, the value of selling excess capacity in summer months for DESC should be recognized.

As noted, the impact of this issue is large on two fronts. First, using a 14% reserve margin versus a 21% reserve margin requirement alters the timing of DESC's capacity needs. This directly impacts the avoided capacity cost estimates, since the lower requirement capacity is not needed as early in the forecast period. Second, the use of low-cost resources such as interruptible load and market-sourced capacity purchases represents a lower cost of capacity that is avoided in the change case.

Power Advisory Assessment

In Power Advisory's view, capacity requirements are not typically bifurcated as base and short-term as has been done by DESC. Rather, the capacity requirement is generally set and resources are procured to meet the overall capacity need. As a result, capacity value should be determined based on the avoided cost of a combustion turbine generator rather than market purchases. Combustion turbines are used as the proxy capacity resource in many markets because they represent the 'default' capacity resource. Power Advisory concurs with Mr. Horii.

3.5.3 DESC Capacity Cost Assumptions

Intervenors disagreed with a number of DESC assumptions that led to different estimates of capacity cost.

Mr. Horii raised a concern that DESC understates capacity cost with its choice of a 100 MW solar change case and a 93 MW peaking resources.

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[138] DESC Neely Rebuttal, p. 11.

[139] ORS Horii Surrebuttal, p. 8-9.

> "I use a 93 MW change in capacity between the base case and the change case because 93 MW is the capacity of the CT units that DESC adds for new capacity. Because of the lumpiness (limited flexibility of sizing) of CT plants, a 100 MW or a 93 MW change result in the same Change Case expansion plan. However, since the cost difference between the Change Case and the Base Case expansion plans are divided by the capacity change (100 MW or 93 MW), the choice of capacity change amounts will affect the final dollar per kW avoided capacity cost. Using the 100 MW change results in an avoided cost that is 7% lower than the avoided cost using the 93 MW change."[140]

DESC disagrees with this approach. DESC Witness Neely states:

> "PURPA specifically provides that a utility may use a capacity change of up to 100 MW to calculate avoided costs. Using a capacity change of 100 MW is consistent with the avoided energy costs and with the Company's prior calculations. Moreover, using a 93 MW capacity change as Mr. Horii suggests would not address his concern about the "lumpiness" in the calculation. The only way to avoid such "lumpiness" would be to add additional resources that exactly equal the amount needed to meet the reserve margin requirement each year, which is unreasonable."[141]

The choice of asset life also impacts the estimate of capacity value because it influences the cost estimate of new capacity that is displaced by the resource. DESC uses a 60-year asset life for combustion turbines based on its depreciation study.

> "It therefore is entirely appropriate and evidence based to use a 60-year economic life when considering the annual cost of a CT unit. To suggest using a shorter economic life is inconsistent with the actual useful life of these assets and the depreciation analysis reviewed and accepted by the Commission and results in DESC customers overpaying avoided capacity costs." [142]

ORS witness Horii provides evidence that using a 60-year asset life assumption, in isolation, leads to an understatement of the capacity cost.

> "While CT lives can be extended far beyond their original expected lives, such an extension would require expensive plant overhauls. DESC's avoided cost model did not include major overhaul costs. Had major overhaul costs been included, a 60-year economic life could have been used, however the resulting avoided capacity costs would likely be similar in

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[140] ORS Horii Direct, p. 39.

[141] DESC Neely Rebuttal, p. 13.

[142] DESC Neely Rebuttal, p. 12.

magnitude to the estimates produced using a 20-year economic life without major overhaul costs."[143]

Power Advisory Assessment

Power Advisory agrees with Mr. Horii that the capacity between the base case and the change case should be aligned. DESC's use of a 100 MW solar change case and a 93 MW combustion turbine resource base case serves to understate avoided capacity costs by 7%.

Power Advisory also agrees that a 60-year asset life assumption is not reasonable for estimating avoided capacity costs. This ignores associated major maintenance fixed costs as noted by Horii, and is contrary to typical industry assumptions in assessing fixed costs of new capacity. As noted, 20 years is a reasonable economic life assumption and this assumption is used in many markets throughout the United States. Absent adjustment to reflect incremental fixed costs associated with a 60-year asset life, a 20 year asset life should be assumed in calculating capacity value.

3.5.4 Avoided Capacity Cost Conclusions and Recommendations

Power Advisory believes DESC's approach serves to understate avoided capacity costs. Power Advisory recommends that the avoided capacity rates proposed by ORS Witness Horii in Direct Evidence be approved, with one potential correction. [144] The capacity rate for solar should be adjusted to reflect an ELCC value for a 93 MW increment above the current existing and contracted solar capacity. Power Advisory's understanding is this is currently 1,048 MW, which implies a capacity value of about 4% as outlined above.

[143] ORS Horii Surrebuttal, p. 10.

[144] ORS Horii Direct, p. 41.

4. FORM CONTRACT POWER PURCHASE AGREEMENTS, COMMITMENT TO SELL FORMS, AND OTHER RELATED TERMS AND CONDITIONS

4.1.1 Background on Commercially Reasonable Terms and Conditions

Act 62 specifies that the Commission should treat QFs on a fair and equal basis with utility-owned resource while protecting ratepayer interests. The relevant sections of the Act as it relates to this chapter of the report include the following (emphasis added):

- "Within such proceeding the commission shall approve one or more standard form power purchase agreements for use for qualifying small power production facilities not eligible for the standard offer. Such power purchase agreements shall contain provisions, including, but not limited to, **provisions for force majeure, indemnification, choice of venue, and confidentiality provisions** and other such terms, but shall not be determinative of price or length of the power purchase agreement. The commission may approve multiple form power purchase agreements to accommodate various generation technologies and other project specific characteristics."[145]

- "A small power producer shall have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed notice of commitment to sell form to the electrical utility. The commission shall approve a standard notice of commitment to sell form to be used for this purpose that provides the small power producer a reasonable period of time from its submittal of the form to execute a power purchase agreement. **In no event**, however, **shall the small power producer**, as a condition of preserving the pricing and terms and conditions established by its submittal of an executed commitment to sell form to the electrical utility, **be required to execute a power purchase agreement prior to receipt of a final interconnection agreement from the electrical utility**."[146]

- "Any decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public."[147]

[145] Act 62. Section 58 41 10 (A)

[146] Act 62. Section 58 41-10. (D)

[147] Act 62. Section 58-41-20. (A)

- "In implementing this chapter, the commission shall treat small power producers on a fair and equal footing with electrical utility-owned resources by ensuring that power purchase agreements, including terms and conditions, are **commercially reasonable** and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA."[148]
- "In establishing standard offer and form contract power purchase agreements, the commission shall consider whether such power purchase agreements should prohibit any of the following: (a) **termination of the power purchase agreement**, **collection of damages from small power producers**, or commencement of the term of a power purchase agreement prior to commercial operation, if delays in achieving commercial operation of the small power producer's facility are due to the electrical utility's interconnection delays"[149]
- "The commission is expressly directed to consider the potential benefits of terms with a longer duration [than 10 years] **to promote the state's policy of encouraging renewable energy**." [150]

In this chapter, we examine terms and conditions of the Standard Offer PPA, the Large QF PPA and the Notice of Commitment to Sell Form, and consider their commercial reasonableness.

As specified by Act 62 a critical standard for assessing the reasonableness of the terms and conditions is the degree to which they are commercially reasonable. In the most basic sense commercially reasonable means terms and conditions that are consistent with the concepts of good faith and fair dealing. For a PPA this requires a balancing of various principles and concepts including: (1) the terms and conditions should conform to industry norms and what is typical, with good comparables being other PURPA PPAs; (2) result in an appropriate alignment of risk, with risks best managed by those who have control over them; (3) the terms and conditions should not unduly impair the ability of the QF to secure financing. For example, if there is an unreasonable risk of termination of the PPA that cannot be adequately mitigated by the QF, or financial penalties that would imperil the ability to cover debt service, without a reasonable opportunity to remedy, or other significant risks related to the cash flows, the project would be in jeopardy of not securing financing; and (4) the terms and conditions should be reasonable from the perspective of

[148] Act 62. Section 58-41-20. (B) (2)

[149] Act 62. Section 58-41-20. (E) (3) (a)

[150] Act 62. Section 58-41-20. (F) (2)

ratepayers and reflect the objective in the Act to reduce the risk placed on the using and consuming public. [151]

In our comments below, we have attempted to strike a reasonable balance between treating QFs on a fair and reasonable basis and protecting ratepayer interests, while striving to reduce the risk placed on the using and consuming public.

4.1.2 Reasonableness of 10-year PPA Contract Length in South Carolina

As discussed, Act 62 represents a delicate balancing of the interests of the consuming public and the interests of QFs, while striving to reduce the risk placed on the using and consuming public. However, as various parties pointed out the Act was passed unanimously in the South Carolina House and Senate. Given the effort devoted to drafting this legislation it would appear that there was an expectation by legislators that the Act would engender a response beyond the filings by various electric utilities. Nonetheless, Act 62 by no means establishes securing financing or ensuring QF project development as a threshold. However, we expect that the Commission would be interested in understanding the implications of the proposed avoided costs on the resulting opportunities for QF development in South Carolina, recognizing that the Act provides:

> "Electrical utilities, subject to approval of the commission, shall offer to enter into fixed price power purchase agreements with small power producers for the purchase of energy and capacity at avoided cost, with commercially reasonable terms and a duration of ten years. The commission may also approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, which must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including but not limited to, a reduction in the contract price relative to the ten year avoided cost."[152]

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[151] Reflecting the balancing of these principles and the appropriate risk allocation, the QF is ultimately responsible for project construction and operation and the terms and conditions should provide proper incentives to ensure that these responsibilities are discharged in a manner the project provides the value that the utility has contracted for "the Scheduled Commercial Operation Date shall be no more than three years from the date the Effective Date."

PacificPower "Oregon Standard Power Purchase Agreement (New QF)", approved by the Public Utility Commission of Oregon, effective August 11, 2016, Section 2.3.

https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Power_Purchase_Agreement_for_New_Firm_QF_And_Intermittent_Resource_with_MAG.pdf

[152] Act 62. 58-41-20 (F)(1)

Contract length was an important issue in this proceeding, with a number of intervenors arguing that contract lengths longer than 10-years were essential if QFs were to secure regularly-available market-rate financing, under the term employed by Johnson Development Associates, Inc. Witness Ms. Chilton. In her direct testimony, Ms. Chilton, representing JDA, emphasized that for QFs to attract commercially reasonable and market-rate financing both the initial term and PPA must be strong enough to attract capital.[153] She further states

> "The longer the contract term, accompanied by a reasonable avoided cost-based purchase price, the more mainstream capital will be available for QF development. PURPA and FERC regulations defer to Commissions to direct PPA terms. In South Carolina, Act 62 recommends a ten-year term as a starting point, but does not limit PPAs to ten years. Indeed, Act 62 expressly encourages this Commission to support longer-term contracts as a means of promoting renewable energy."[154]

Ms. Chilton recommends that

> "the Commission set the tenor of length of PPA contracts at a minimum of fifteen (15) years with appropriate conditions as set forth in SC Code Ann. § 58-41-20(F)(1) to facilitate the opportunity to obtain financing for a majority of QFs in South Carolina."[155]

In his rebuttal testimony, Mr. Kassis responds by stating:

> "Contrary to Ms. Chilton's assertion that PURPA requires pricing and initial term strong enough to attract financing, FERC is concerned with adhering to Congress' fundamental requirement that avoided cost rates may not exceed incremental costs. If an avoided cost rate is accurate but low, it may not be raised above incremental costs for any reason, even if the reason is to attract more favorable financing."[156]

In her surrebuttal, Ms. Chilton states that FERC expects that the calculation of avoided cost together with other PPA terms that are fair to QFs will result in "just and reasonable prices for consumers and the development of QFs."[157]

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[153] JDA Chilton Direct, p.6.

[154] JDA Chilton Direct, p.8.

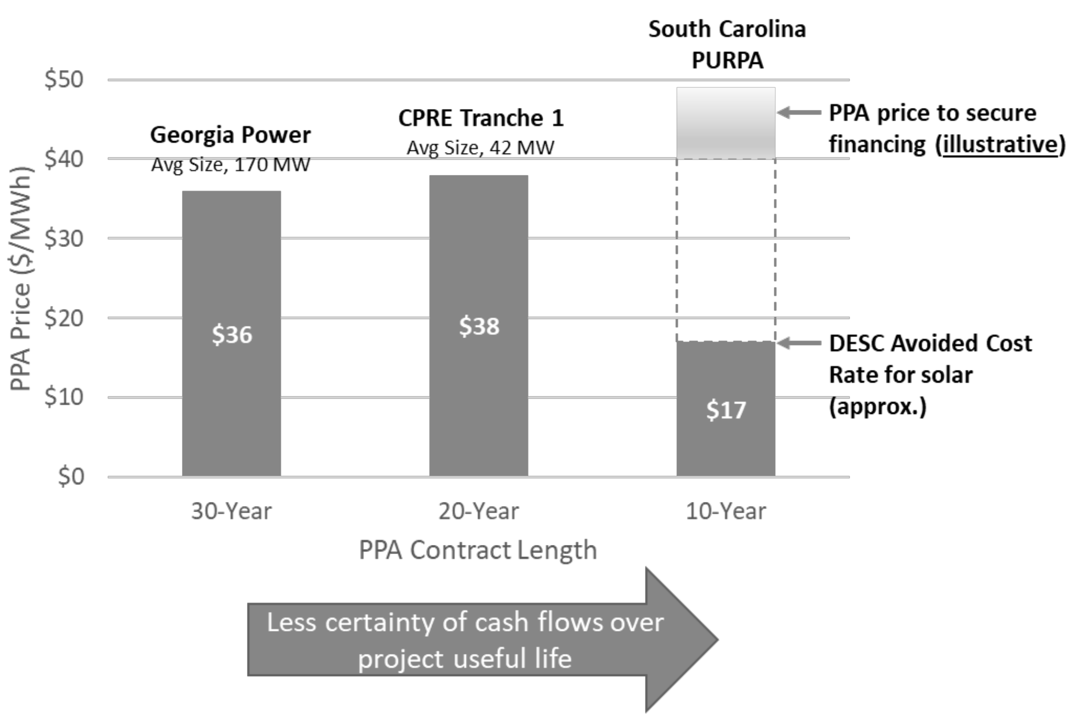
[155] JDA Chilton Direct, p.10.

[156] DESC Kassis Rebuttal, p.14

[157] JDA Chilton Surrebuttal, p.3.

At the heart of whether the 10-year term is sufficient or not to enable financing under reasonable terms is the contract price. As contract length shortens, the required PPA price to secure conventional financing increases owing to the riskiness of the cash flows in the post-PPA period. This relationship is illustrated in Figure 7. The figure contains PPA pricing for 30-year, 20-year and 10-year PPAs. In late 2017, through competitive bid, Georgia Power contracted for 510 MWs of solar in Georgia with an average price of $36/MWh for 30-year contracts.[158] Eighteen months later, in 2019, Duke contracted for 550 MWs of solar projects in North Carolina (CPRE Tranche 1) for an average price of $38/MWh for 20-year contracts. Owing to the increased riskiness of the cash flows in the post-PPA period, the $/MWh price for a 10-year PURPA contract in South Carolina would need to exceed the $38/MWh figure. The problem is that the currently proposed avoided cost rates for DESC are expected to be about well below these results. [159] Thus, without higher longer contract length, the solar industry would not be able to finance PURPA projects in South Carolina because they would not be economical. While the bar on the right shows a required PPA price to secure financing, Power Advisory has not calculated that price so the top part of the bar is illustrative only.

Figure 7. PPA Price ($/MWh) vs. Contract Length (Years)



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[158] Georgia Power, "Georgia Power renewable growth to continue throughout 2018: 970 MW of solar capacity online today, 510 MW of new solar contracts recently awarded" March 13, 2018

https://southerncompany.mediaroom.com/2018-03-13-Georgia-Power-renewable-growth-to-continue-throughout-2018

[159] DESC Neely Direct, p. 14 lines 9-12.

It's also important to note two things that could drive required PPA prices in South Carolina even higher:

- The Investment Tax Credit (ITC) declines from 30% in 2019 to 26% in 2020, to 22% in 2021 to 10% in 2022, thus eroding solar economics over time (and drives required PPA prices higher)
- The comparable PPA rates for 30 year and 20 year PPAs have average project sizes of 170 MWs and 42 MWs, respectively. These sizes are much higher than the average South Carolina PURPA projects. Thus, project economics would be worse.

Two other investor concerns related to the 10-year contract length include the following:[160]

- It is hard to forecast the avoided cost of a given utility to understand what the pricing will be 10 years from now.
- There is regulatory risk in terms of whether there will still be a utility purchase obligation 10 years from now, or what the terms and conditions of the purchase obligation will be.

This is in contrast to an organized power market such as PJM, ISO-NE or ERCOT where there is a liquid market for electricity in the post-PPA term and far more confidence in the price forecasts. In addition, a hedge product can be used to put a floor under the electricity prices. As a result, shorter term PPAs are possible in these organized markets. By contrast, the risks in South Carolina in the post-PPA period are much harder to mitigate.

Intervenor Proposals for Terms and Conditions for Longer PPA Lengths

It is important to note that the Intervenors were planning to propose terms and conditions for longer PPA lengths, however, Power Advisory did not receive these prior to submission of this report.

4.1.2.1 Comparison with PURPA Contract Lengths in Other States

Power Advisory reviewed contract lengths in some of the most prominent PURPA states, where the market for PURPA projects has been the greatest over the past 10 years in megawatts. The average contract length of 15 states as shown in the figure is currently 14.1 years, down from 15.5 years when taking into account regulatory actions over the past few years. The current contract lengths ranged from 2 to 25 years, with a median of 15.

[160] Norton Rose Fulbright, Project Finance NewsWire, August 2019, p.2.
https://www.projectfinance.law/newswire-archive/august-2019/

Figure 8. PURPA Contract Length by State Sorted Longest to Shortest [161]

State	Current Term (Years)	Date Effective	Increase/Decrease	Previous Term (Years)
Montana	25	Apr-19	Retained same	25
Vermont	25		Same	25
Oregon	20	Mar-16	Retained same	20
Wyoming	20	Jun-16	Retained same	20
New Mexico	20		Same	20
Michigan	20		Same	20
Utah	15	Jan-16	Decrease	20
Washington	12	Jun-19	Increase	5
Connecticut	12		Same	12
North Carolina	10	Oct-17	Decrease	15
South Carolina	10	May-19	Retained same	10
California	10		Same	10
Mississippi	5		Same	5
Georgia	5		Same	5
Idaho	2	Aug-15	Decrease	20
Average	**14.1**			**15.5**

The most significant change in contract length over the past few years occurred in Idaho, the third largest PURPA market over the last 10 years in megawatt additions, according to data from EIA.[162] In August 2015, at the request of the utility, the Idaho Public Service Commission reduced the PURPA contract length from 20 years to 2 years.[163] That made it the shortest PURPA PPA contract

[161] Power Advisory, based on various regulatory filings, Standard Offer PPAs and associated documents

[162] Data are from the US Energy Information Administration (EIA), EIA-860 database: https://www.eia.gov/electricity/data/eia860/

[163] Idaho Public Utilities Commission, "Idaho commission reduces contract length for some PURPA projects to two years" Case No. IPC-E-15-01, AVU-E-15-01, PAC-E-15-0, August 19, 2015. https://puc.idaho.gov/press/150820_PURPAfinal_files.pdf

length in the US and remains that way to this day. Although the QF was eligible for continual renewal of its contract every two years at then-current avoided costs, this effectively turned the project into a merchant plant. Since this ruling, no new QF projects of greater than 1 MW have become operational in Idaho according to data from EIA. In the wake of this change, several other utilities have requested their regulator reduce contract lengths to shorter durations. Some of the results of those requests are as follows:

- In Utah, the utility requested a reduction from 20 to 2 years, but the Public Service Commission decided to reduce it more moderately, from 20 to 15 years[164]
- In Wyoming, PacifiCorp asked its regulator to reduce contract length from 20 years to 3 years but was denied[165]

On the flip side, in June 2019, Washington State increased its contract length from 5 years to 12-15 years.[166]

4.2 Summary of Resolved Issues

DESC, SBA and ORS provided direct, rebuttal (DESC) and surrebuttal (SBA, ORS) testimony as it relates to the Standard Offer PPA, Large QF PPA and Notice of Commitment to Sell Form (NOC).[167] They also provided oral testimony at a hearing held on October 14 and 15, 2019.

The parties have come to what is effectively a negotiated agreement through these various rounds of testimony on several issues originally cited in Mr. Levitas' direct testimony as warranting revision. This is viewed by Power Advisory as evidence that these negotiated terms are fair and reasonable.

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[164] Public Service Commission of Utah, "In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities – Docket No.15-035-53 Order" Issued January 7, 2016 https://pscdocs.utah.gov/electric/15docs/1503553/2712701503553o.pdf

[165] "25. The Commission denies RMP's Application for authority to amend Schedules 37 and 38 to reduce the contract term of its PURPA PPAs with QFs from 20 years to three years. The Commission concludes that RMP failed to meet its burden to demonstrate that the proposed modification of the Wyoming PPA contracts is reasonable, will solve an alleged system-wide problem, and is in the public interest of Wyoming ratepayers."

Public Service Commission of Wyoming, "In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities," Docket No. 20000-481-EA-15 (Record No. 14220), June 23, 2016.

Similar decisions reached by the Wyoming PSC for the other utilities, notably PacifiCorp.

[166] Washington State Legislature, Chapter 480-106-050 https://apps.leg.wa.gov/wac/default.aspx?cite=480-106&full=true

[167] JDA Chilton did not make specific revisions to PPA terms but rather expressed general concerns with respect to project financeablilty including length of term and price, etc.

Changes DESC made to the Standard Offer and Form PPA in light of input from SBA include:

- Relief would be provided from liquidated damages for interconnecting utility delays both for interconnection facilities and network upgrades.
- Removal of provisions requiring EPC and O&M contracts to be in a form and substance satisfactory to the Buyer.
- DESC provided a form of surety bond in an exhibit to the contract.
- Revisions with respect to Seller's indemnification of the Buyer for Environmental Liability, and personal and property damage.
- Removal of provisions enabling the Buyer to terminate the contract in an Extraordinary Event.
- Maximum duration of Force Majeure extended to 9 months.
- Adding current and prospective investors to the list for whom confidential information may be shared.
- Added a provision that enables the Seller to terminate the contract in the event of high interconnection costs (e.g., $75,000/MW).

Requests that SBA withdrew in light of other concessions made by DESC:

- Completion Date to be based on estimated in-service date per the Interconnection Agreement.
- Early Termination Fee to be based on estimated losses at 95% of projected output in the event of early termination by the Buyer.
- Expansion of Nameplate capacity should not require consent of the Buyer.
- Clarifications with respect to curtailment of output based on "system conditions".
- Deletion of Section 11.6 with respect to the description of liquidated damages.
- Eliminate requirement for the Buyers prior written consent for pledging the agreement or associated revenues to Financing party.
- Removing restrictions with respect to public announcements on the construction and operations of the contracted facility.
- In the event that damages are owed by the Seller, the amount of the Notice of Commitment (NOC) to Sell fee of $5,000 should be deducted from the amount of damages owed.
- Clarification with respect to NOC provision to keep DESC whole for any damages arising from breach of warranty, representation or covenant of the NOC.

- Request that a cure period be added, such that a LEO can be terminated if the Seller ceases to comply with the requirements of the LEO and the deficiency fails to be cured within 10 business days.

In addition, Mr. Horii[168] and Mr. Lawyer[169] representing ORS also presented suggested revisions to the Standard Offer, Form PPA and NOC. Each of the matters below were resolved satisfactorily from ORS' perspective:

- Clarifications in Section 8(iii) of the NOC with respect to "which entity (the QF or DESC) is responsible for installing additional facilities to establish adequate interconnection facilities, and whether the QF is eligible for any payments or damages due to delays." DESC provided clarification.
- Clarifications in Section 6.1(a) of the Standard Offer PPA respect the phrase "expected range of uncertainty based on historical operating experience." DESC revised this section of the PPA.
- Correction of references to SCANA in the forms to Dominion Energy South Carolina, Inc.
- Clarification with respect to "the 'Limiting Provisions' of Section of the Rate PR-1 Tariff". ORS later agreed that no clarification was required.

Ms. Chilton, representing JDA, provided direct testimony with respect to the ability of QF's to obtain regularly available market-rate financing[170]. Her testimony focused on PPA pricing and PPA duration, and did not delve into other terms and conditions of the Standard Offer, Form PPA or NOC. [171]

However, there remain several notable points of difference between the SBA and DESC that need to be resolved. These matters are reviewed in the next sections of this chapter, along with Power Advisory's recommendations for resolution.

4.3 PPA Standard Offer and Terms and Conditions

4.3.1 Liquidated Damages and Extension Payments

As a basic principle, liquidated damages should be the parties' best estimate at the time they sign a contract of the damages that would be caused by a breach of the contract. DESC's original Standard Offer and Form PPA stated that if the Seller is unable to meet the Completion Deadline liquidated damages of $55/kW-AC will apply. The Completion Deadline is set 12-months following

[168] ORS Horii Direct, p. 45-41.

[169] ORS Lawyer Direct, p. 7.

[170] JDA Chilton Direct, p. 5.

[171] JDA Chilton Direct, p. 6.

the Effective Date (i.e., contract execution date). In addition to Excusable Delays (e.g., triggered by Force Majeure), the Seller can extend the Completion Deadline subject to an Extension Payment of $0.11/kW-AC per day for up to 120 days. As originally drafted, DESC may terminate the PPA if the Completion Deadline is missed.

In his direct testimony, Mr. Levitas stated that the liquidated damages proposed by DESC are excessive and unreasonable and that they are significantly larger than the liquidated damages proposed by Duke and substantially higher than those established by Consumers Energy in Michigan. [172,173] Mr. Levitas asserted that liquidated damages proposed are in excess of any actual damages that would be incurred by DESC and recommended that DESC adopt liquidated damages in the amount of $5,000/MW-AC for first 20 MW, plus $2,000/MW-AC for any capacity above 20 MW.[174]

Mr. Levitas did not have an objection with the Extension Payment in principle, however, he argued that these are excessive when viewed in combination with what he characterized as exorbitant liquidated damages proposed by DESC.[175] That said, Mr. Levitas was concerned that Excusable Delays related to Interconnecting Utility delays "pertains only to the construction of required Interconnection Facilities and doesn't include required Network Upgrades (i.e., necessary improvements to the grid beyond the Delivery Point)".[176]

In his interrogatory response, Mr. Folsom wrote that the liquidated damages amount approximates the value of one year of operation under the PPA and asserted that this is appropriate because it would take approximately one year to find a replacement resource. Further, Mr. Folsom wrote that DESC viewed this amount of liquidated damages to be appropriate because late withdrawal of speculative projects can be disruptive to the connection queue. Mr. Folsom added that DESC did not perform any specific analysis but used their own knowledge and understanding of ratepayer risk.[177]

However, in light of changes to the avoided costs, DESC reduced the liquidated damages amount from $55,000/MW-AC to $41,000/MW-AC. Specifically, in his rebuttal testimony Mr. Kassis stated:

> "Liquidated damages in this context are generally estimated as a proxy amount to compensate the utility for any costs or losses it incurs in obtaining replacement

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[172] Note that Duke originally proposed liquidated damages in the amount of 2% of expected project revenues and amended their proposal in response to Mr. Levitas' testimony.

[173] Consumers Energy Company. Standard Offer Tariff and Standard Offer Power Purchase Agreement. Michigan Public Service Commission Case No. U-18090.

[174] SBA Levitas Direct, p. 10.

[175] SBA Levitas Direct, p. 11.

[176] SBA Levitas Direct, p. 11.

[177] DESC Response to First Power Advisory Interrogatories, #1-5.

> capacity and energy due to a QF's non-performance. This is ultimately a business decision that should vary upon the size of the facility.
>
> Contrary to Mr. Levitas's assertion, these liquidated damages are not higher than liquidated damage amounts in prior DESC negotiated power purchase agreements. Further, Mr. Levitas reduces the basis of liquidated damages for larger projects over 20 MW for no apparent reason. However, these larger plants (over 20 MWs) create additional risks for DESC's reliance on this energy because it must factor delivery of this energy into its resource planning and larger facilities could lead to greater losses if the energy is not delivered pursuant to the terms of the agreement. Nevertheless, as a result of DESC's amended solar avoided cost, DESC reduced this amount from $55/kW-AC to $41/kW-AC in its revised filing submitted on September 20, 2019."[178]

In Mr. Levitas' surrebuttal testimony, he stated he did not believe the reduction to be sufficient and referred to Duke's acceptance of lower liquidated damages; specifically, he states:

> "In its revised filing, DESC has reduced that amount to $41,000/MW. While SCSBA appreciates this reduction, the [liquidated damages] are still extremely high – for example, a 50 MW project would face more than $2 million in liquidated damages – and also bear no reasonable relationship to actual damages that DESC would suffer in the event that a contracted Facility fails to be placed in service. Mr. Kassis acknowledges that [liquidated damages] must bear some relationship to actual damages, stating that "Liquidated damages in this context are generally estimated as a proxy amount to compensate the utility for any costs or losses it incurs in obtaining replacement capacity and energy due to a QF's non-performance." It is hard to fathom how the loss of a single project from the resource plan could cause millions of dollars of damage to the utility.
>
> With respect to energy purchases, to the extent that DESC would enter into long-term contracts in the absence of QF supply, it would be easy enough for it to do so upon early termination of a QF PPA and recover its actual damages. Where damages are so easily measured, there is simply no need for liquidated damages. And given declining natural gas prices and DESC's insistence that long-term PURPA PPAs are bad for ratepayers, it's very hard to understand why Mr. Kassis thinks the company would be damaged if it had to procure energy in another fashion. Any damages are likely to be largely administrative in nature. The reason that I proposed a reduced per MW [liquidated damage] amount over 20 MW is because such administrative damages are not proportional to the size of the

[178] DESC Kassis Rebuttal, p. 18-19.

> facility and are not likely to be substantially greater in the case of a 50 MW facility that with a 20 MW one."[179]

During witness examination by Vice Chairman Williams, Mr. Kassis was asked to describe the nature of costs and losses that would be experienced by DESC. Mr. Kassis responded by stating:

> "…the actual calculation is based on the capacity, it's based on the avoided cost, and it's based on the length of a year -- the term, which was -- which is what we believe it would take to replace that resource. Granted, avoided cost is -- is low, so it drives the number down lower, which was the change. But we also recognized in the market, that it would take approximately a year to replace that resources, so it's -- it includes the – the avoided energy. We believe it reasonably compensates us for opportunities -- say, for instance, for another developer to bring in a project, who then could essentially reach finance, etc. -- our administrative costs. So those – that formulated approach isn't anything different or new, it's the same one we've used on -- on a 1,048 megawatts that we've signed or -- or have commercially operated so far."[180]

During witness direct examination by Mr. Adams, Mr. Levitas stated that the "single biggest open issue is the amount of liquidated damages or LDs Dominion would require a QF to pay if the PPA is terminated without the facility having been placed in service" and urged the adoption of Duke's proposed formula.[181]

Power Advisory Assessment

The two sides are far apart on this issue. In fact, DESC's liquidated damages under the $41,000/MW-AC formula for a 5 MW plant would be 8.2 times that proposed by SBA and 10.3 times for a 30 MW plant.

By contrast, Duke and SBA agreed on a formula for liquidated damages that yields a much lower amount. The agreed upon formula is the average annual estimated capacity payments under the Agreement over the Term for up to 15 MW and $10,000/MW-AC thereafter.[182]

The damages to the purchasing utility are largely mitigated by the fact that PPA pricing is based on avoided costs which in turn are based on the incremental cost of energy and capacity but for the purchase from the QF the utility would generate or purchase. Therefore, we believe that it is inappropriate that the liquidated damages should approximate one year of payments at avoided cost rates as proposed by DESC. By definition PPA payments reflect utility costs. Therefore, Power

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179 SBA Levitas Surrebuttal, p. 4-5.

180 Hearing Vol. 1, p. 117 (DESC Kassis).

181 Hearing Vol. 2, p. 445 line 12 to p.446 line 16 (SBA Levitas).

182 Duke proposed this and Mr. Levitas agreed to it during the Duke Hearing, (Vol. 1, p. 315 lines 1-22).

Advisory believes that the liquidated damages proposed by DESC are too high. A more reasonable formula for liquidated damages would be the one agreed upon by Duke and SBA.

4.3.2 Guaranteed Energy Production

In DESC's Standard Offer and Form PPA, the Seller estimates the expected annual output of Net Energy for each year of the contract term ("Contract Quantity"). The Guaranteed Energy Production is eighty-five percent (85%) of the Contract Quantity. A Shortfall occurs if the Facility fails to deliver the Guaranteed Energy Production in any particular Contract Year. If there is a Shortfall, the Seller is subject to Performance Liquidated Damages which must be paid within 30 days of receipt of an invoice. The Buyer can terminate the PPA if the Facility fails to deliver eighty-five percent (85%) of the Guaranteed Energy Production in any two consecutive Contract Years.

In his direct testimony, Mr. Levitas asserts that DESC's proposal is not commercially reasonable, though SBA acknowledges that this contract provision varies widely in the industry. SBA recommends that DESC should adopt the Duke shortfall amounts (i.e., 70%) and DESC should adopt Duke's approach which is calculated based on a rolling two-year average.[183]

In his rebuttal testimony Mr. Kassis states that the Guaranteed Energy Production provision is "purely a commercial matter to address risk arising from a QF's failure to perform in accordance with the contract".[184] He goes on to state that the Standard Offer and Form PPA stipulates "that the QF will operate at and maintain an expected performance of 95 percent", and thus DESC has provided additional flexibility by defining Shortfalls at or below 85 percent. Further, the Seller is in the best position to address such shortfall. Mr. Kassis further says that the termination provision is reasonable because the "QF can, in large measure, control the variables affecting its ability to meet this requirement".[185]

The effect of termination would be that the parties would enter into a new PURPA PPA at new avoided cost rates. Duke's PPAs do not contain this termination provision. SBA suggests that LDs should be the Buyer's sole remedy in the event of a Shortfall.[186]

During witness examination by Vice Chairman Williams, Mr. Kassis was asked about the reasonableness of the termination provisions associated with the Guaranteed Energy Production. Mr. Kassis responded:

> "...every developer that we've signed a contract with has been able to reach that

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[183] SBA Levitas Direct, p. 14.

[184] DESC Kassis Rebuttal, p. 20.

[185] DESC Kassis Rebuttal, p. 21.

[186] SBA Levitas Surrebuttal, p. 6.

> production level and -- unless they have a major issue with equipment or programming of things like inverters… if you don't meet the provision two years in a row, which means you're essentially neglecting the asset, then somebody else should have the opportunity to take advantage of providing a resource. That's simply a measure to keep the assets very -- as reliable as you can get with an intermittent resource is what our expectations are."[187]

Vice Chairman Williams also asked Mr. Kassis about use of other remedies, rather than termination, who responded:

> "…when you put provisions that like that, then people actually commit and follow through and do what they're going to say they're going to do in the contract."[188]

During direct witness examination by Mr. Adams, when discussing termination due to a Shortfall, Mr. Levitas stated that "termination would, in fact, serve no purpose because under PURPA, the QF would be entitled to enter into a new PPA." [189]

Power Advisory Assessment

On an annual basis solar output is very predictable. While Power Advisory is concerned about consistency between DESC and Duke terms and conditions given that facilities will be located within the same state, we do not recommend a lowest common denominator approach to establishing terms and conditions.

In the San Diego Gas & Electric Company's Standard Offer PPA in California, the Guaranteed Energy Production (GEP) is equal to 70% of the average Contract Quantity over a 2-year period for wind and 85% for all other technologies. In the case that this GEP is not met, the seller pays liquidated damages, but the contract is not terminated. [190]

In the Avista Corporation's Standard Offer PPA contract in Washington State, on a monthly basis, if the monthly production is less than 90% of the month's Net Output Estimate for the corresponding month, then a Shortfall Energy Price applies for the Shortfall Energy which is the lower of the Market Energy Price and the Avoided Cost Rate. The contract is not terminated. [191]

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[187] Hearing Vol. 1, p. 118 (DESC Kassis).

[188] Hearing Vol. 1, p. 119 (DESC Kassis).

[189] Hearing Testimony, Vol. 2, p. 447 (SBA Levitas).

[190] Renewable Market Adjusting Tariff Power Purchase Agreement, approved by California Public Utilities Commission in Decision 13-05-034 effective May 23, 2013.

[191] Avista Corporation, Washington, Standard form of Power Purchase Agreement for Qualifying Facilities with Capacity of 5 MW or less, Rev 08/2019.

In the Puget Sound Energy Standard Offer PPA contract in Washington State, the Seller is responsible for providing at least the Annual REC Quantity specified in the REC Contract, which is executed in conjunction with the PPA. [192] If the facility does not generate enough RECs in a given year then they need to source the shortfall from a third party. The contract is not terminated.

While we are mindful of inconsistencies between DESC and Duke, we do not agree that this is sufficient reason to lower the bar, especially if the guaranteed amount is easily achievable.

That said, Power Advisory has not found precedent in other contracts to include contract termination in the event of a shortfall. While following the termination the QF can enter into another PURPA PPA, this would potentially be at a lower rate. Our research indicates that providing a termination right for a PPA where pricing is based on avoided costs and thereby reflects the buyer's cost of generating or purchasing the power is outside the norm. Therefore, we believe such a provision disproportionately increases project risks relative to the harm that would be realized by customers and believe that the termination if the Facility fails to deliver 85% of the Guaranteed Energy Production in any two consecutive Contract Years right should be eliminated.

4.3.3 Energy Storage

In Mr. Levitas' direct testimony, he pointed out that the DESC PPA is silent on energy storage, despite requirements from Act 62. He noted that energy storage would typically only be considered for facilities greater than 2 MW, therefore absence of language leaves it up to PPA negotiation without Commission oversight.[193]

In Mr. Kassis' rebuttal testimony he states that per the Settlement Agreement filed in Docket No. 2017-370-E on November 30, 2018, DESC agreed to file with the Commission for its approval either "proposed avoided cost rates for energy and capacity that provide accurate pricing for storage as a separate resource; or proposed technology-neutral avoided cost rates for energy and capacity that provide accurate pricing for dispatchable renewable generating facilities such as solar + storage (e.g., hourly pricing)." [194]

Mr. Kassis goes on to quote Section 14 of Act 62 which states, "[t]he provisions of Section 58-41-20 shall not be interpreted to supersede the conditions of any settlement entered into by an electrical utility and filed with the commission prior to the adoption of this act."

Therefore, as explained by Mr. Kassis, DESC plans to meet its obligation under the Settlement by making a filing with the Commission on or before December 31, 2019, and that Act 62 requires

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[192] Puget Sound Energy, Washington, Schedule 91, Power Purchase Agreement, effective February 10, 2017.

[193] SBA Levitas Direct, p. 15.

[194] DESC Kassis Rebuttal, p. 23.

that each utility's avoided cost methodology account for energy storage, but it does not expressly address, much less mandate, terms and conditions.[195]

During direct witness examination by Mr. Adams, when discussing termination due to a Shortfall, Mr. Levitas stated:

> "Dominion has not proposed contractual terms for the inclusion of energy storage devices. As you know, they're required to propose a solar-plus storage rate, but as things stand, developers will have no idea how to qualify for that rate. And, again in contrast, Duke has proposed an energy storage protocol in its Large QF PPA and has now agreed to incorporate the same protocol in its Standard Offer PPA."[196]

Power Advisory Assessment

Power Advisory believes that it would have been desirable for DESC to outline the provisions for energy storage as part of this proceeding. However, given that Act 62 is not intended to "supersede the conditions of any settlement entered into by an electrical utility and filed with the commission", we do not find a reason for DESC to be required to provide terms and conditions related to energy storage at this time. More importantly, imposing associated terms and conditions would deprive the parties from the opportunity to negotiate provisions of these terms and conditions.

4.3.4 Termination Payment

Per DESC's proposed Standard Offer and Form PPA, if Buyer terminates the agreement due to an event of default on or after the Commercial Operation (with some prescribed exceptions), the Seller will be required to pay a Termination Payment according to the following formula, which results in a price floor on damages. As demonstrated by the formula below, the floor increases the Termination Payment to a level that is likely to be greater than cost of the replacement energy.[197]

[195] DESC Kassis Rebuttal, p. 23.

[196] Hearing Vol. 2, p. 447 lines 7-15 (SBA Levitas).

[197] DESC Folsom Amended Exhibit JEF-1 to Direct Testimony, Section 11.4.

Termination Payment is the NPV of

$$(RE_{price} - \text{Net Energy Rate}) \times (Dt_{erm} \times E_{daily}) + C + O$$

Where:

RE_{price} is price per kWh for commercially available renewable energy from a substantially similar renewable facility located in the same state in the same applicable market(s)

(RE_{price} – Net Energy Rate) shall not be 50% of the Net Energy Rate (i.e., based avoided costs)

D_{term} is the number of days remaining on the term

E_{daily} is the expected daily kWh of Net Energy to be delivered during the remainder of the term, and no less than the Contract quantities

C is all reasonable costs and expenses incurred by Buyer resulting from event of default (e.g., legal fees)

O is all other amounts such as owed by the Seller (e.g., overdue Delay Damages, Extension Payments, etc.)

In his direct testimony, Mr. Levitas argues that this provision is not commercially reasonable and should be deleted. He says that since payments under the contract are based on avoided costs and DESC is not assigning a capacity value, there should be little harm to the Buyer for termination. Mr. Levitas goes on to point out that "Witness Folsom emphasizes how bad PURPA PPAs are for ratepayers, in which case they should welcome any that go away".[198]

Further, Mr. Levitas asserts that the floor on damages established is completely unreasonable. If Net Energy Rate is $32/MWh and market price for renewable energy is $34/MWh, damages would be set to $16/MWh, even though the actual incremental cost of procuring replacement renewable energy would $2/MWh. Further, there is no reason to base the cost of procuring replacement energy on renewable energy, as DESC is not buying RECs and contract price is based on avoided energy.[199]

Overall, Mr. Levitas states opposition to post-COD damages, but if they are included, Shortfall LDs payable should be clearly waived. SBA recommends that the Termination Payment reflect the

[198] SBA Levitas Direct, p. 18.

[199] SBA Levitas Direct, p. 18.

Duke approach such that DESC is made whole for any overpayment to the Seller relative to applicable avoided cost rates.[200]

In his rebuttal testimony, Mr. Kassis emphasized that the approach to the measurement of damage was reasonable, stating:

> "DESC accounts for these generating assets in its resource plan and relies on these plants performing pursuant to the contract. Moreover, Mr. Levitas fails to take into account that when a QF terminates after COD, DESC incurs damages in the form of lost opportunities, e.g., self-build, RFP, or other competitive solicitation or procurement options."[201]

During direct witness examination by Mr. Adams, when discussing the termination payment, Mr. Levitas stated that:

> "Dominion proposes a totally unreasonable 50 percent floor on such damages that could potentially result in a massive and unjustified windfall to the Company. I explain this in detail in both my direct and surrebuttal testimony. And I would also note that there is no comparable floor on Dominion's damages to the QF should they be in breach of the agreement resulting in termination."[202]

During examination by Vice Chairman Williams, when asked about DESC's termination payment, Mr. Levitas stated that DESC's proposal is "unprecedented in my experience and -- and, if I had to say, maybe the single most unreasonable thing in the whole document."[203]

Power Advisory Assessment

The proposed Termination Payment does not appear to be consistent with any actual damages or consequences experienced by DESC as a result of contract termination. As discussed below, it is common that the termination fee may include compensation to the buyer for any over payment, lost value (i.e., difference between the contract and market price) or legal fees associated with termination. Some jurisdictions may include cost of replacement energy over a period of time (i.e., 24 months), while others leave the determination of termination payments up to commercially reasonable negotiations.

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[200] SBA Levitas Direct, p. 19.

[201] DESC Kassis Rebuttal, p. 25 lines 15-19.

[202] Hearing Vol. 2, p. 448 lines 3-11 (SBA Levitas).

[203] Hearing Vol. 2, p. 495 (SBA Levitas).

Some examples of how other jurisdictions treat termination payments resulting from Seller default follow:

- Duke Energy Carolinas, LLC (North Carolina)[204] - The termination fee equals the amount of (a) the minimum monthly charges which would have been payable during the unexpired term of the Agreement plus (b) the Early Termination Charge. The Early Termination Fee is the total Energy and/or Capacity credits received in excess of the sum of what would have been received under the Variable Rate for Energy and/or Capacity Credits applicable at the initial term of the contract period and as updated every two years, plus interest.

- Pacific Power & Light Company (Oregon)[205] - The termination fee is the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for the Average Annual Generation that Seller was otherwise obligated to provide at the Mechanical Availability Guarantee for a period of twenty-four (24) months from the date of termination, plus any cost incurred for transmission purchased to deliver the replacement power to the Point of Delivery, plus the estimated administrative cost to the utility to acquire replacement power.

- San Diego Gas & Electric Company (California)[206] - If either Party exercises a termination right after the Commercial Operation Date, the non-defaulting Party shall calculate a settlement amount ("Settlement Amount") equal to the amount of the non-defaulting Party's aggregate Losses and Costs less any Gains, determined as of the Early Termination Date. (Note, the terms Gains, Losses and Costs, are defined terms, however open to commercially reasonable interpretation.)

- Avista Corporation (Washington)[207] - In the event of default or early termination due to failure to perform, Avista can retain the contract security.

Therefore, Power Advisory recommends that DESC remove the floor on damages and amend the formula to reflect the cost of replacement energy at the then-current costs of replacement energy, as follows:

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[204] Duke Energy Carolinas, LLC. Terms and Conditions for the Purchase of Electric Power. Effective March 1, 2016. NCUC Docket No. E-100 Sub 140.

[205] Oregon Standard Power Purchase Agreement (New QF), approved by the Public Utility Commission of Oregon, effective August 11, 2016.

[206] Renewable Market Adjusting Tariff Power Purchase Agreement, approved by California Public Utilities Commission in Decision 13-05-034 effective May 23, 2013.

[207] Avista Corporation, Washington, Standard form of Power Purchase Agreement for Qualifying Facilities with Capacity of 5 MW or less, Rev 08/2019.

Termination Payment is the NPV of

$$(\text{Rate}_{RE} - \text{Net Energy Rate}) \times (D_{term} \times E_{daily}) + C + O$$

Where:

Rate_{RE} is the is price per kWh of replacement energy

(Rate_{RE} – Net Energy Rate) shall not be less than zero

D_{term} is the number of days remaining on the term

E_{daily} is the expected daily kWh of Net Energy to be delivered during the remainder of the term, and no less than the Contract quantities

C is all reasonable costs and expenses incurred by Buyer resulting from event of default (e.g., legal fees)

O is all other amounts such as owed by the Seller (e.g., overdue Delay Damages, Extension Payments, etc.)

4.4 Notice of Commitment to Sell Form

The following is a summary of areas of dispute between SBA and DESC with respect to DESC's proposed NOC form.

4.4.1 Limiting PPA Eligibility Following Termination

DESC's proposed NOC form states that if a QF submits an executed NOC form but fails to execute a PPA in a timely fashion, in addition to termination of the LEO, the QF will not be eligible for fixed-pricing for a period of two years.

Mr. Levitas states in his direct testimony that restricting eligibility for fixed-pricing for a period of two years is "overly harsh and not authorized by PURPA". Mr. Levitas recommends that a QF who fails to perform should be liable for the same damages per the Standard Offer and Form PPA (i.e., Mr. Levitas recommends \$5,000/MW-AC for first 20 MW, plus \$2,000/MW-AC for any capacity above 20 MW.)[208]

[208] SBA Levitas Direct, p. 25-26.

Mr. Kassis, in his rebuttal testimony, stated that DESC has concerns with respect to gaming, and that in "its Reform NOPR, the FERC proposes varying rates for energy, which further supports inclusion of this provision." [209]

During witness cross examination conducted by Mr. Adams (on behalf of SBA), Mr. Kassis acknowledged that the NOPR is not a binding regulation, is subject to public comment, and may be amended or not ultimately be promulgated.[210]

Power Advisory Assessment

While it is reasonable that DESC would want to prevent speculation, restricting the ability to pursue fixed-pricing is inconsistent with PURPA. Therefore, Power Advisory recommends adopting Mr. Levitas' recommendation of implementing damages per the Standard Offer and Form PPA for failure to execute a PPA in a timely fashion.

4.4.2 365 Day In-service Deadline

DESC's proposed NOC form states that the seller must deliver power within 365 days of submitting the NOC form.

In Mr. Levitas' direct testimony, he states that the NOC form establishes a commitment to enter into a PPA within 30 days, which would have sufficient requirements with respect to in-service deadlines. If the in-service deadline is to remain, it should only be applicable when there are sufficient network resources for interconnection at the time of the deadline.[211]

In his direct testimony, Mr. Folsom asserts that QF's cannot be viewed as having to make a substantial commitment if the project is more than a year from actual power delivery. He also references similar precedents established in other jurisdictions; for example, Idaho has a requirement to deliver power within 365 of establishing a LEO. More stringent requirements in other jurisdictions have also been upheld, for example, Texas has a 90-day delivery window.[212]

In is surrebuttal testimony, Mr. Levitas stated that SBA is "prepared to accept DESC's proposed requirement that Seller commence delivery within 365 days of its Notice of Commitment to Sell, provided that such obligation is subject to the same Excusable Delays as the in-service deadline under DESC's proposed PPAs."[213]

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[209] DESC Kassis Rebuttal, p. 36.

[210] Hearing Vol. 1, p. 68 (DESC Kassis).

[211] SBA Levitas Direct, p. 28.

[212] DESC Folsom Direct, p. 24.

[213] SBA Levitas Surrebuttal, p. 12.

Power Advisory Assessment

Power Advisory believes that Mr. Levitas' proposal has merit and is reasonable. It is logical to align PPA terms with LEO requirements, and that the NOC form acknowledge Excusable Delays that would impact the in-service deadline.

4.4.3 Eligibility Pre-Conditions

In addition to other pre-conditions (i.e., commitment, site control, fee), DESC's proposed NOC form states the QF is required to have secured all land-use approvals and environmental permits that would be required to have the facility in service within 365 days. Further, the Seller is required to have an executed System Impact Study Agreement.

In his direct testimony, Mr. Levitas states that environmental permits and land use approvals are expensive and time consuming and that it is unreasonable to incur such expenses without securing a price for the project. This is not a requirement of the PPA, and there is no logic for having more onerous requirements in LEO. Further, the Seller should only be required to execute a System Impact Study Agreement if one has been tendered to it by the DESC.[214]

Mr. Folsom, in his direct testimony, emphasized that the "NOC Form is purely a creature of the Act". QFs can submit a NOC without attempting to negotiate with DESC. In DESC's view, QFs must make substantial commitments to sell output in order to establish a LEO. States have discretion with respect to LEOs and the proposal reflects DESC institutional knowledge and experience (e.g., need to reduce speculative projects).[215] Mr. Folsom also cites precedent from other jurisdictions implementing "control-and-approval" concepts in the LEO framework.[216]

In his rebuttal testimony, Mr. Kassis quotes:

> "Reform NOPR, the FERC specifically permits states to require a QF to make a showing that it has "satisfied or, is in the process of undertaking, at least some" enumerated items in the Reform NOPR, such as obtaining site control, filing an interconnection application, securing permitting, and certain other "reasonable criteria to allow the QF to demonstrate its commercial viability and financial commitment.""[217]

[214] SBA Levitas Direct, p. 27.

[215] DESC Folsom Direct, p. 21-22.

[216] DESC Folsom Direct, p. 25.

[217] DESC Kassis Rebuttal, p. 37.

Mr. Kassis also notes that Mr. Horii finds these provisions reasonable.[218]

During direct witness examination by Mr. Adams, Mr. Levitas emphasised that requiring permits prior to securing pricing certainty would be unreasonable and stated that it is “not a reasonable requirement without the QF knowing what its project economics are.”[219] Mr. Levitas goes on to state:

> “I also don't believe it's consistent with PURPA to require that a seller at either established interconnection service or signed a system impact study agreement as a condition of LEO formation because this improperly places control over LEO formation in the hands of the utility.” [220]

Power Advisory Assessment

Power Advisory recommends that since SBA has agreed to the 365-day in-service date requirement, that QFs be allowed to secure permits after formation of a LEO. This makes it consistent with the PPAs which do not require permits be obtained before execution. Also, the requirement is unnecessarily onerous on the QF. In fact, DESC is making it more onerous to form a LEO than to enter into a PPA. The QF already has to meet the requirement of being in-service within 365 days or risk termination and liquidated damages. This requirement alone will result in QFs with viable projects moving forward with LEO formation.

[218] DESC Kassis Rebuttal, p. 37.

[219] Hearing Vol 2, p. 449 (SBA Levitas).

[220] Hearing Vol 2, p. 449-450 (SBA Levitas).